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Assumptions for the

ANNUAL ENERGY OUTLOOK 1990

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Assumptions for the *Annual Energy Outlook 1990*

Energy Information Administration
Office of Energy Markets and End Use
U.S. Department of Energy
Washington, DC 20585

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Preface

This report serves as an auxiliary document to the Energy Information Administration publication *Annual Energy Outlook 1990 (AEO)* (DOE/EIA-0383(90)), released in January 1990.

The *AEO* forecasts were developed for five alternative cases and consist of energy price and consumption projections by major fuel and end-use sector at a national level of aggregation. Full documentation on the models used to develop the *AEO* forecasts is available in *PC-AEO Forecasting Model for the Annual Energy Outlook 1990* (DOE/EIA-M036, March 1990).

The purpose of this report is to present important quantitative assumptions, including world oil prices and macroeconomic growth, underlying the *AEO* forecasts. The report has been prepared in response to external requests, as well as analyst requirements for background information on the *AEO* and studies based on the *AEO* forecasts. Because this document is intended for use in the National Energy Strategy process, a large amount of background detail has also been included in this year's report.

This report is a product of the Energy Information Administration, Office of Energy Markets and End Use, under the direction of W. Calvin Kilgore (202/586-1617). This report was prepared under the general supervision of John D. Pearson, Director, Energy Analysis and Forecasting Division (202/586-6160), and Richard D. Farmer, Chief, Supply Analysis and Integration Branch (202/586-1458).

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1. Introduction

This *Assumptions* report is an auxiliary document to the *Annual Energy Outlook 1990 (AEO)* (DOE/EIA-0383(90)). It presents a more detailed discussion of the assumptions underlying the forecasts in the *AEO*. The forecasts presented in the *AEO* are outputs of the PC-AEO Forecasting Model (PC-AEO), a personal computer-based modeling system using a popular spreadsheet software. The PC-AEO is an economic equilibrium modeling system, with component modules representing electric utility pricing and fuel consumption, coal supply and end-use pricing, petroleum product pricing, crude oil production, and natural gas production and pricing. Also included are energy demand models representing end-use energy consumption by major end-use sector. The PC-AEO accounts for the interactions among these components of energy markets and projects prices and quantities for which energy supply equals demand.

In the *AEO*, five forecast cases are presented: a base case, low and high world oil price growth, and low and high macroeconomic growth. The base case is the central forecast. The four other cases are presented to reflect the uncertainty inherent in any forecast of the future. They are based on reasonable lower and upper bounds on two key factors that affect energy trends—world oil price and the rate of economic growth, and characterize a reasonable range of uncertainty for domestic oil production and petroleum imports under current energy policy.

This *Assumptions* report presents the oil price and economic growth assumptions, as well as other quantitative assumptions for specific demand and supply modules of PC-AEO, that were used by EIA in developing the *AEO* base case and alternative scenario projections. Further details on the methodology, data, and assumptions are available from the contacts listed in the Preface.

2. World Oil Price and Macroeconomic Assumptions

World Oil Price

As the past decade has shown, movements in world oil prices can be very unpredictable. (World oil price is defined as the average cost of imported crude oil to U.S. refiners.) Changes in policy decisions and market conditions have caused wide price swings. Given the political and economic uncertainties that exist in the world, there is no reason to believe that projecting oil prices will be any easier in the future, particularly in the near term. Over the longer term, however, basic trends in world oil supplies and demands point to broad indications about the ultimate course of world oil prices.

The base case outlook reflects this longer term view. While extreme circumstances such as oil price wars and temporary supply disruptions could cause major price swings for a few years, these forces do not reflect long-run trends and are not incorporated into this model.

EIA world oil price projections are given in Table 1 and Figure 1, and a comparison of projections made by others is shown in Figure 2. The EIA base case projection is based on a detailed analysis of Organization of Petroleum Exporting Countries (OPEC) capacity expansion plans, non-OPEC production trends and world oil demand (including the responsiveness of demand to increased prices). Non-OPEC production is expected to level off in the mid 1990's and then gradually decline throughout the projection period. World oil demand, however, is expected to increase in response to increased world economic growth and current low world oil prices. These two factors point to an increased dependence upon OPEC oil in the future.

Pattern Evident in Phased Price Changes

The pattern of price changes can be broken down into three distinct phases. Phase I (through 1992) is characterized by continued large volumes of OPEC production capacity in excess of the demand for their oil. In this time period OPEC's problem is to deal with this excess capacity in a manner that precludes a price collapse. Prices fail to keep up with inflation which stimulates the demand for OPEC's oil and allows more of their production capacity to be utilized.

Phase II (1992 to 1998) is a period of adjustment in which prices increase rather rapidly. Non-OPEC production is expected to plateau and then start declining during this period, resulting in increased demand for OPEC production. Prices are expected to increase and OPEC excess production capacity is expected to decline. This is due to the time lags involved in the installation of new production capacity and the slowing of demand growth once prices begin to increase. Demand adjustments take time to occur, which means that several years of higher prices are needed in order to slow demand growth. It also takes time for OPEC members to expand their production capacity in response to the higher prices. This period of relatively rapid price adjustment is consistent with historical experience where changes in market structure have been followed by periods of rapidly changing prices.

In Phase III (1998 to 2010), increases in oil demand and oil production capacity return to a rough equilibrium. As a result, oil prices continue to increase, but at a decreasing rate on average over time as higher prices induce more and more use of alternative forms of energy and unconventional sources of oil itself.

The base case projection shows the expected trends in world oil prices. Given the uncertainty regarding assumptions about future oil discoveries, economic growth rates, the share of oil in energy markets, ratios of oil consumption to gross domestic product (GDP) and other factors, other reasonable assumptions are possible which would lead to different price paths. The low and high price paths (Table 1) associated with the base case form a band of uncertainty about world oil prices.

Table 1. World Oil Prices, 1979-2010
(1989 Dollars per Barrel)

	Price Case		
Year	Low	Middle	High
1979	--	$34.88	--
1980	--	50.02	--
1981	--	49.86	--
1982	--	42.44	--
1983	--	35.71	--
1984	--	33.86	--
1985	--	30.76	--
1986	--	15.55	--
1987	--	19.49	--
1988	--	15.18	--
1989	$17.10	17.70	$18.30
1990	14.40	16.80	19.20
1991	14.40	16.10	20.50
1992	14.40	16.50	21.90
1993	14.30	18.00	23.20
1994	14.30	19.40	24.60
1995	14.30	20.40	25.90
1996	15.40	21.90	27.50
1997	16.50	23.50	29.10
1998	17.60	25.20	30.70
1999	18.70	26.70	32.30
2000	19.80	27.80	33.90
2001	20.60	29.00	35.50
2002	21.40	30.00	37.10
2003	22.30	31.10	38.70
2004	23.10	32.00	40.30
2005	23.90	32.90	41.90
2006	24.30	33.80	43.00
2007	24.70	34.70	44.10
2008	25.10	35.50	45.20
2009	25.50	36.20	46.30
2010	25.90	36.90	47.40

Note: Prices represent the U.S. refiner acquisition cost of imported crude oil.
Source: **History:** Energy Information Administration, *Monthly Energy Review*, various issues, DOE/EIA-0035(89)(1989). **Projections:** Energy Information Administration, Office of Energy Markets and End Use, *Oil Market Simulation Model User's Manual*, DOE/EIA-M028.

Figure 1. World Oil Prices, 1970-2010

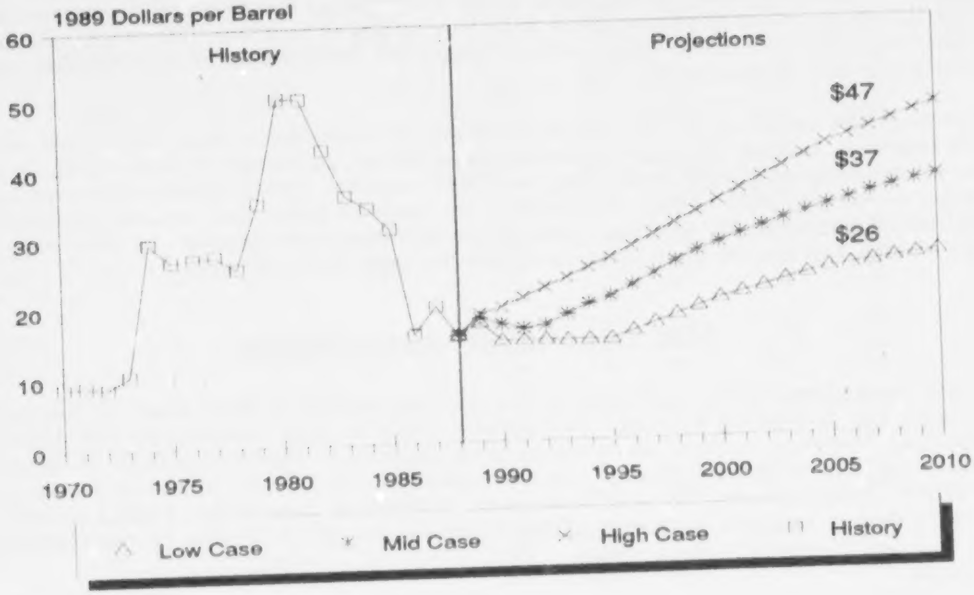
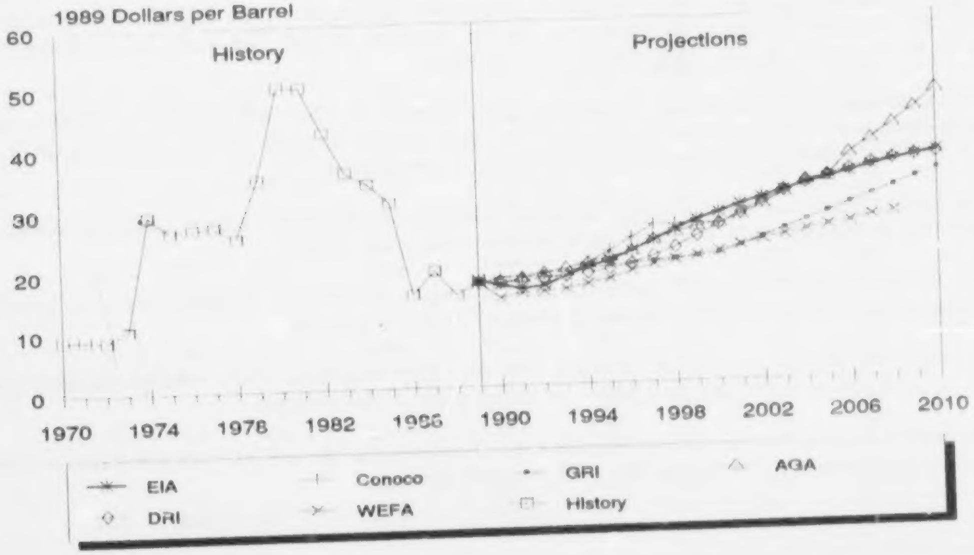


Figure 2. Comparison of EIA Base Case Oil Price Projections with Alternatives



The projections made in the *AEO* incorporate the tendency for prices to fluctuate within the range of the high and low oil price paths. Following history, it is believed that price swings outside this range are unsustainable. While prices may go above this range, it is believed that they will discourage demand and encourage the development of new supplies, thus driving prices back into this range. Similarly, prices below this range will spur consumption and discourage the development of new supplies, with the net result that prices will increase again.

The oil price ranges developed do not represent specific scenarios; that is, there are no low- or high-price world oil balances. Instead, the ranges represent the combined probability of events such as unexpected (whether lower or higher) growth in demand, non-OPEC supplies, OPEC capacity, and other events. The price range for the year 2010 roughly encompasses the range of prices that occurred between 1974-1985. The mid case is presented for analytical convenience and does not represent the most likely outcome; the range of high and low oil price paths represents the most likely outcome.

Macroeconomic Assumptions

The macroeconomic assumptions presented in the *AEO* are similar to those made by the commercially available economic forecasting services. Adjustments made to these forecasts by EIA ensure that the macroeconomic simulation conforms to its energy price projections. Figures 3 through 18 show how these assumptions compare to similar projections of the economy made by Data Resources Incorporated (DRI) and the WEFA Group (formerly Wharton Econometric Forecasting Associates). Table 2 presents the *AEO* projections of the key economic indicators. Table 3 presents the *AEO* indicators of manufacturing output.

Base Case

Real Gross National Product (GNP) grows by an average of 2.4 percent per year between 1988 and 2010. Growth is slightly stronger in the first 12 years of the forecast, reaching 2.5 percent per year between 1988 and 2000. Growth then slows somewhat to an average of 2.3 percent per year between 2000 and 2010, due to slower growth in population and the size of the work force.

Personal expenditures on consumer items decline as a percentage of GNP as exports and investments increase. This realignment in the shares of GNP devoted to consumption, investment and exports represents a natural adjustment to the pattern of growth in the 1980's. During the 1980's, personal consumption expenditures as a share of GNP rose dramatically. This relative strength reflected the fact that consumption fell less than other demand components during the 1980 to 1982 recession and provided much of the strength in the 1986 recovery. In the forecast period, the share of consumption to GNP returns to levels more in line with historical experience.

Likewise, business fixed investment expenditures as a share of GNP fell during the 1980's. As a result, the requirements for replacement investment increases in the forecast period, resulting in a rise in the share of GNP devoted to business fixed investment expenditures.

The U.S. trade deficit has risen rapidly in recent years, a trend which cannot continue indefinitely. The projected rise in exports as a share of GNP reduces this trade deficit.

Inflation, measured by the implicit price deflator, averages 4.8 percent annually over the forecast period. The consumer price level exhibits annual growth of about 5 percent.

Real interest rates decline somewhat between 1988 and 1995 and then attain relative stability (between 3.5 and 4.0 percent above inflation) over the remaining part of the forecast.

Real disposable income levels off at a growth rate of approximately 2.0 percent per year, or almost three-fourths of a percentage point below the 1971 to 1988 average.

Table 2. Key Economic Indicators, 1977-2010

Economic Indicator	History			Compound Annual Growth 1977-1988	Cases	1988	1990	2000	2010	Compound Annual Growth 1988-2010
	1977	1982	1988							
Real GNP (billion 1982$)	2959	3166	4024	2.8%	High	4024	4300	5696	7330	2.8%
					Base	4024	4214	5392	6799	2.4%
					Low	4024	4127	5088	6297	2.1%
Gross Output Manufacturing (billion 1982$)	2020	1941	2410	1.6%	High	2410	2600	3662	4946	3.3%
					Base	2410	2485	3388	4411	2.8%
					Low	2410	2370	3117	3905	2.2%
Real Disposable Personal Income (billion 1982$)	2067	2262	2793	2.8%	High	2793	2998	3718	4617	2.3%
					Base	2793	2935	3562	4358	2.0%
					Low	2793	2871	3407	4110	1.8%
Unemployment Rate (percent)			5.50		High	5.50	5.44	5.72	5.34	
					Base	5.50	5.47	5.83	5.48	
					Low	5.50	5.50	5.98	5.59	
						Annual Rate 1988-1990	Annual Rate 1990-2000	Annual Rate 2000-2010	Annual Rate 1988-2010	
Inflation Rate			3.32%		High	3.88%	3.53%	4.42%	3.96%	
					Base	4.20%	4.78%	4.93%	4.79%	
					Low	4.55%	5.90%	5.31%	5.51%	

Note: In this table, the labels High and Low refer to the economic growth cases in the 1990 *AEO*.
Sources: **History:** U.S. Department of Commerce, Bureau of Economic Analysis, and DRI Input-Output Model History.

Table 3. Indicators of Manufacturing Output, 1977-2010

Economic Indicator	History			Compound Annual Growth 1977-1988	Cases	1988	1990	2000	2010	Compound Annual Growth 1988-2010
	1977	1982	1988							
Gross Output Manufacturing (billion 1982$)	2020	1941	2410	1.6%	High	2410	2600	3662	4946	3.3%
					Base	2410	2485	3388	4411	2.8%
					Low	2410	2370	3117	3905	2.2%
Primary Metals (billion 1982$)	145	97	107	-2.7%	High	107	114	144	160	1.9%
					Base	107	103	129	143	1.3%
					Low	107	92	115	127	0.8%
Chemical & Rubber (billion 1982$)	241	234	294	1.8%	High	294	316	451	616	3.4%
					Base	294	306	424	565	3.0%
					Low	294	294	397	516	2.6%
Stone, Clay & Glass (billion 1982$)	54	45	51	-0.5%	High	51	55	69	83	2.2%
					Base	51	52	65	77	1.9%
					Low	51	50	62	71	1.5%
Paper (billion 1982$)	75	77	99	2.6%	High	99	107	141	181	2.8%
					Base	99	104	134	168	2.4%
					Low	99	99	126	155	2.0%
Food (billion 1982$)	255	283	307	1.7%	High	307	316	402	476	2.0%
					Base	307	315	381	447	1.7%
					Low	307	313	369	427	1.5%

Note: In this table, the labels High and Low refer to the economic growth cases in the 1990 *AEO*.
Sources: **History:** U.S. Department of Commerce, Bureau of Economic Analysis, and DRI Input-Output Model History.

Population growth rates have been slowing for some time. The base case assumption of continued decline in population growth rates is based on the Census Bureau's middle-growth population forecast. This forecast incorporates the effects of immigration, birth rates of all women in the population including immigrants, and mortality rates.

Labor Force. In the period from 1988 to 2000, the labor force growth rate declines to 1.4 percent per year in the base case, compared to a growth rate of 2.2 percent between 1971 and 1988. This trend reflects slowing population growth and a slowing in the rate of entry of women into the labor force. In the post-2000 period, the labor force growth rate falls to 0.7 percent, reflecting aging of the population and fewer younger workers.

Savings and Investment. During the 1980's, total fixed investment as a share of GNP fell sharply. In the forecast period, this share of total fixed investment rebounds slightly and levels off at approximately 15.5 percent, a level consistent with the historical trend. The source of funds to finance this trend comes from two primary sources--households and government.

For households, the savings rate (personal savings as a percent of nominal disposable income) has declined steadily since the mid-seventies. In the forecast period, the savings rate stabilizes at approximately 4.5 percent. While lower than long-term historical rates, the leveling off in this rate prevents further erosion of household savings.

The government effect on savings comes about through two primary channels. State and local governments will continue to accumulate substantial surpluses, mainly because of their pension funds. Equally important, the reduction in the Federal deficit removes what has recently been a large drain on aggregate savings.

The details of other macroeconomic assumptions and interactions and linkages of the model are provided in the model documentation.[1] Detailed sectoral output tables from the base case run provide further information.

High and Low Economic Growth Assumptions

The rate of economic growth in the base case depends on many uncertain factors, such as the interest rate sensitivity of the economy, the future direction of both the trade and the federal deficit, productivity, as well as the assumed path of energy prices. The high and low economic growth assumptions examine a reasonable range of growth based on possible outcomes of these economic uncertainties. Both alternative forecasts exhibit economic expansion, albeit at different growth rates.

The high growth case incorporates larger increases in capital-stock growth, factor productivity and labor force productivity compared to the base case. Real GNP grows by 2.7 percent per year between 1988 and 2010, compared to 2.4 percent per year in the base case. Inflation in the high growth case is lower because of an increased supply of productive factors. Because of the reduced Federal deficit and interest rates, investment and industrial production expands. The exchange rate declines, contributing to greater demand for exports. Industrial production increases since both inflation and interest rates are lower and productivity and export demand are higher than in the base case.

In the low growth case, factors of production are not as available. Prices are higher and productivity increases lower compared to the base case. Both deficits and interest rates remain high, resulting in lower investment and industrial production. Export demand is not as robust, and as industrial production slows, consumer demand expands more slowly. Real GNP grows at the slower rate of 2.1 percent per year over the 22 year forecast period.

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[1] Energy Information Administration, *PC-AEO Forecasting Model for the Annual Energy Outlook 1990: Model Documentation*, DOE\EIA-M036 (Washington, DC, March 1990).

Figure 3. Real Gross National Product

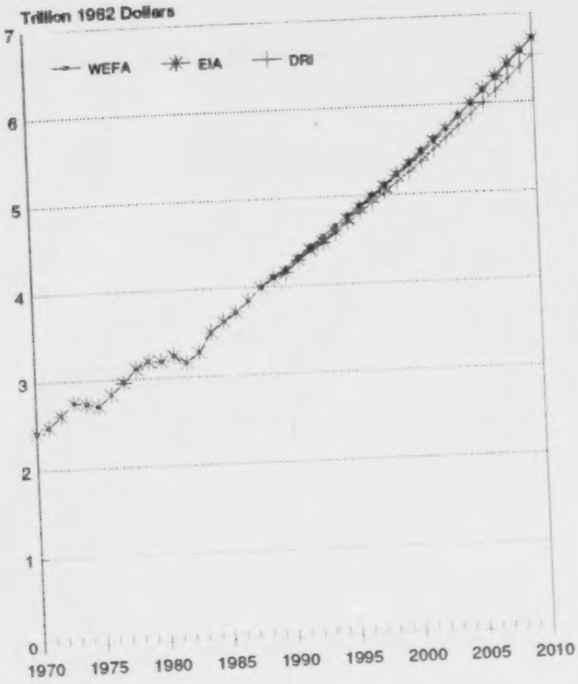

Figure 4. Real Disposable Income

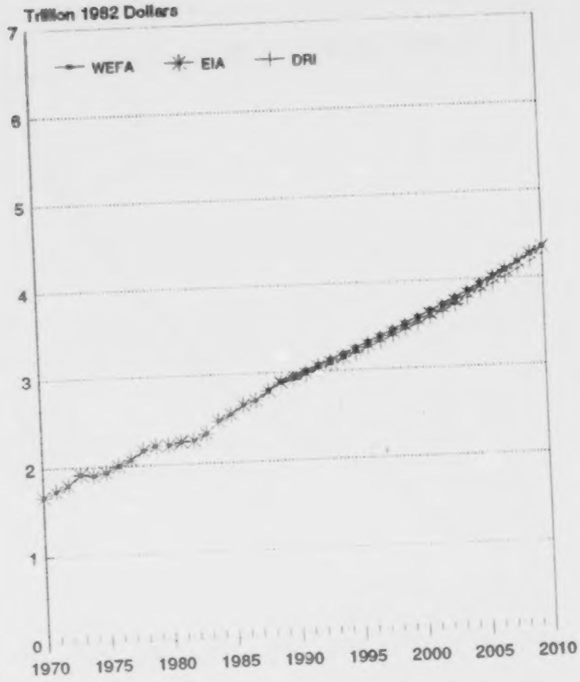

Figure 5. Total Manufacturing Output

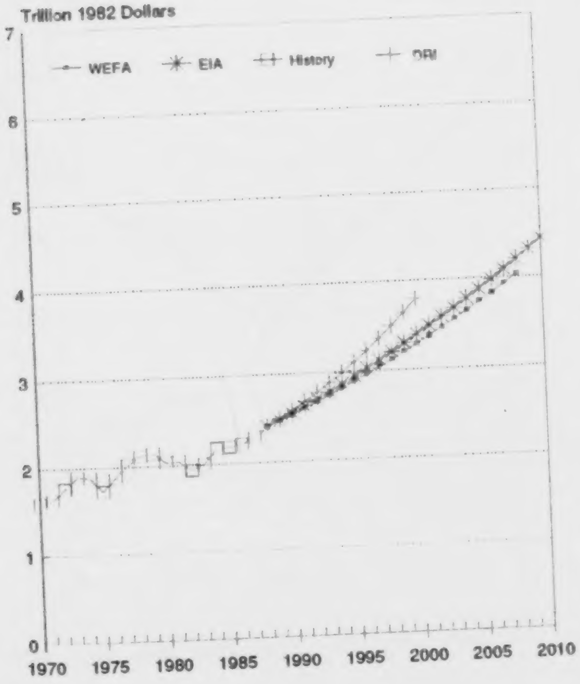

Figure 6. Implicit Price Deflator

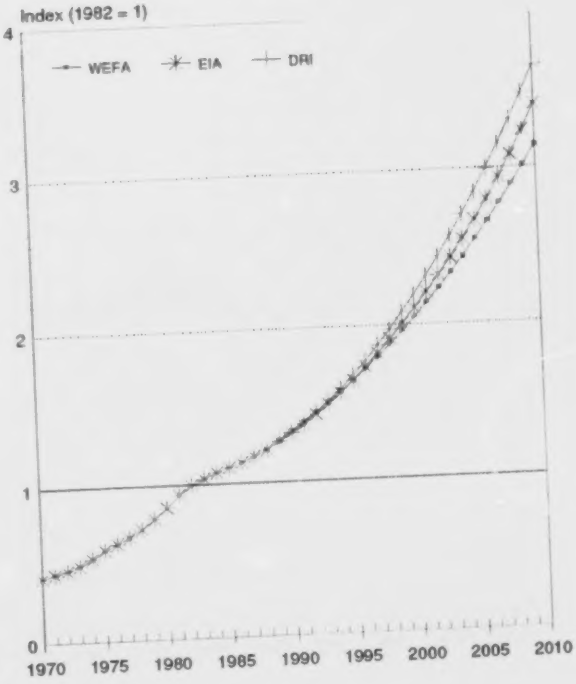

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Figure 7. Consumer Prices

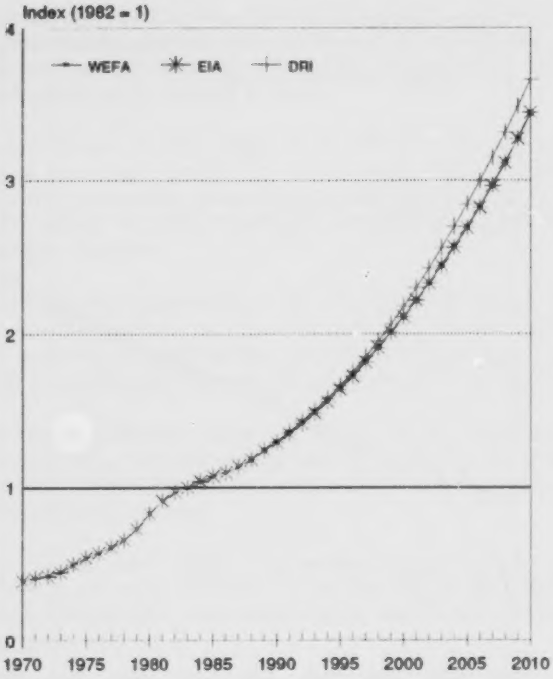

Figure 8. Federal Funds Rate

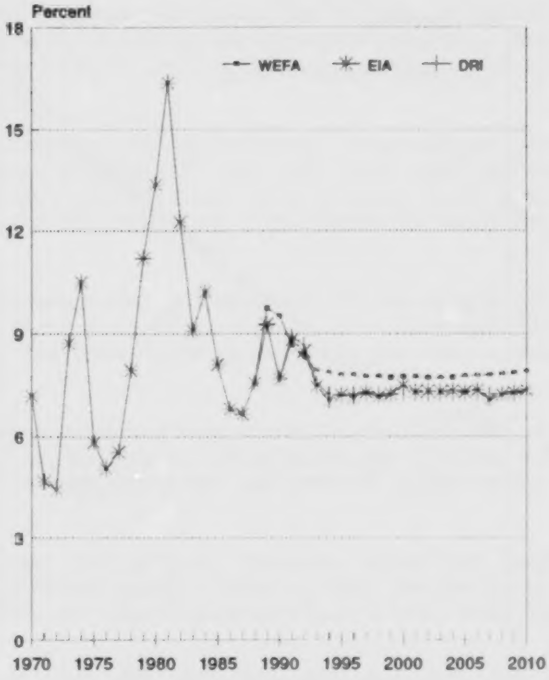

Figure 9. Housing Starts

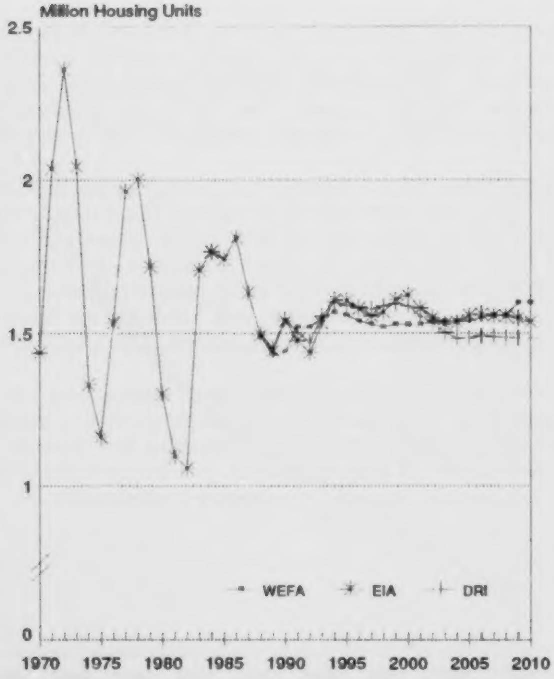

Figure 10. New Car Sales

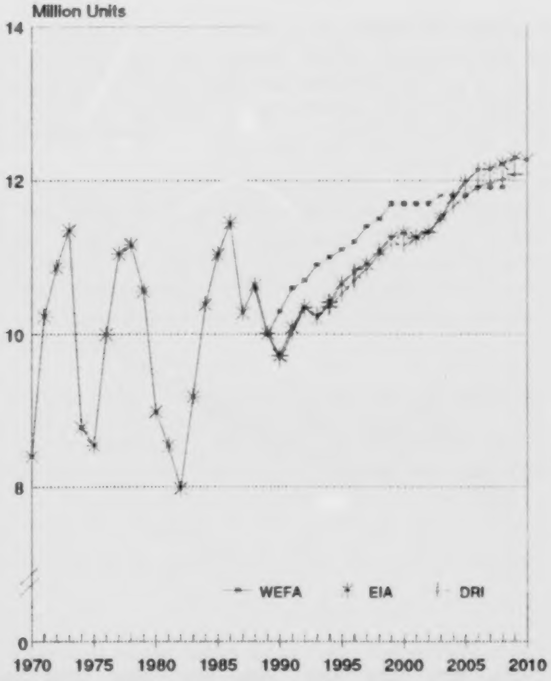

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Figure 11. Chemical and Plastics Industry

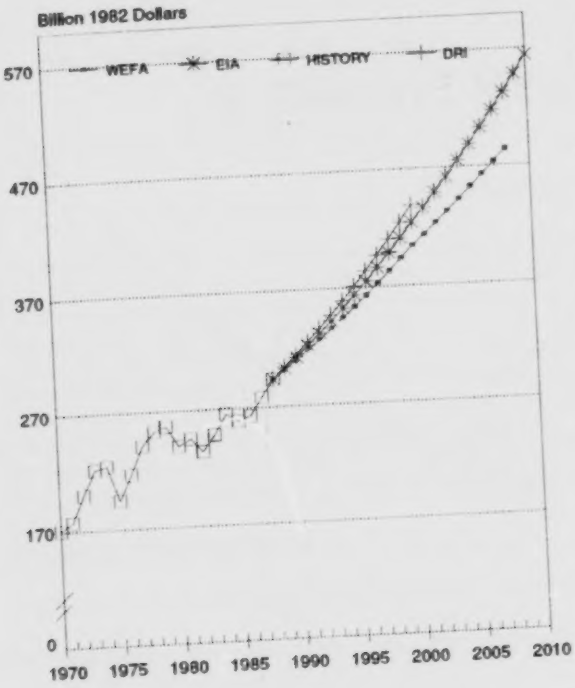

Figure 12. Primary Metals Industry

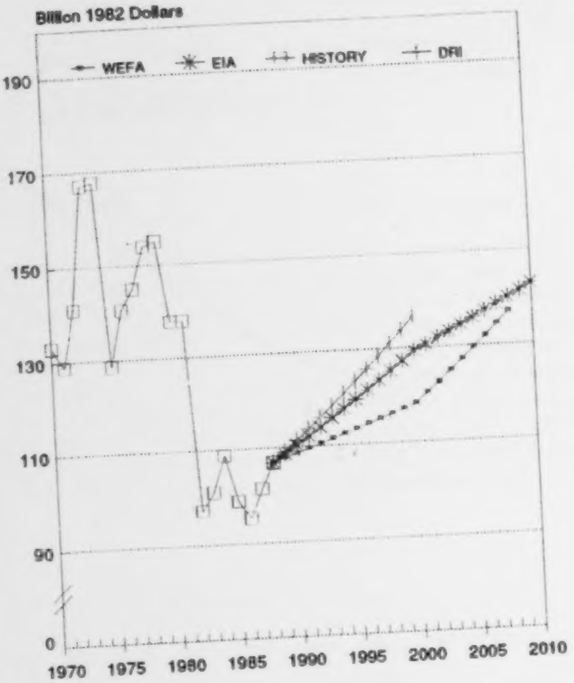

Figure 13. Paper Industry

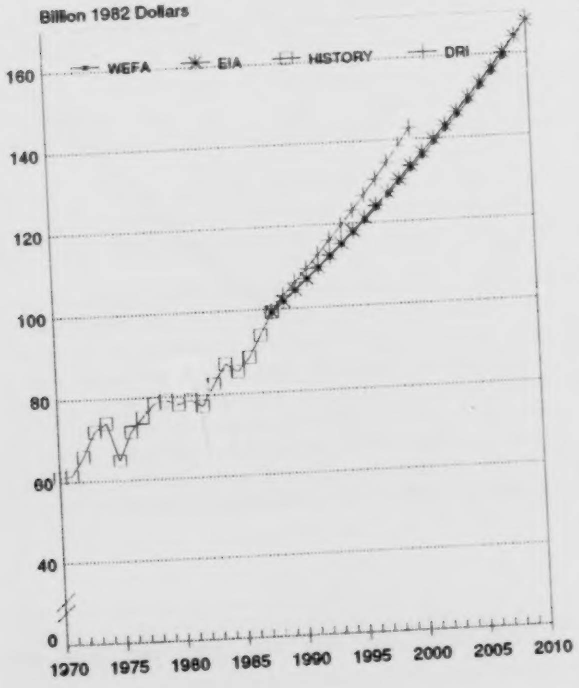

Figure 14. Stone, Clay & Glass Industry

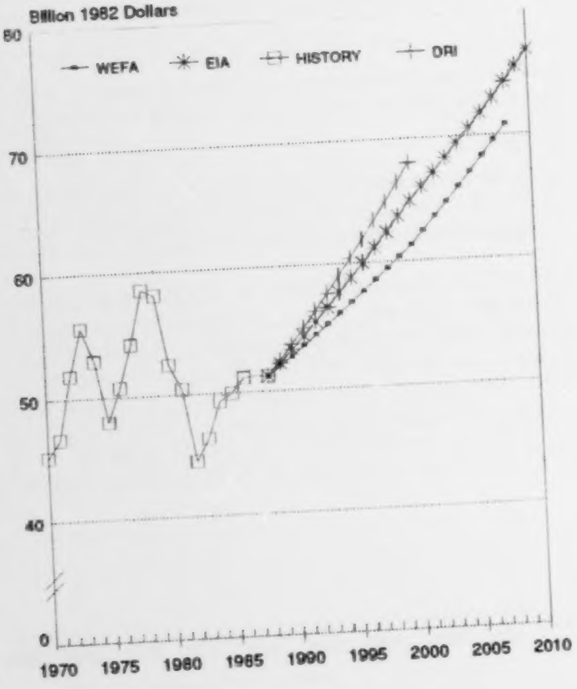

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Figure 15. Food Industry

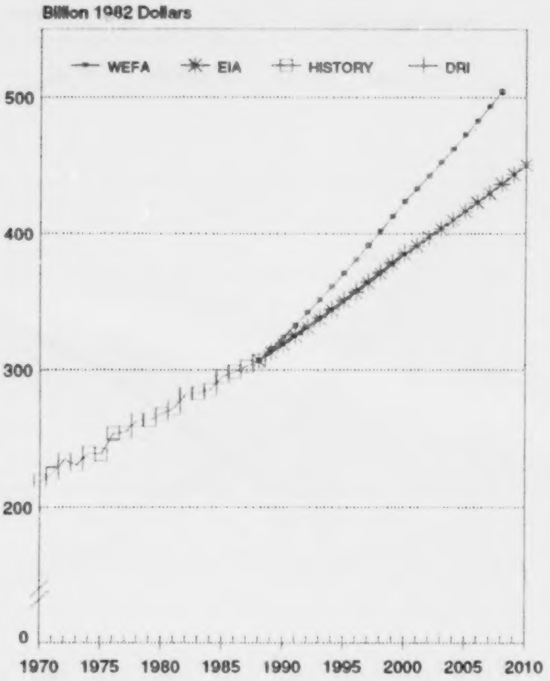


Figure 16. Machinery Industry

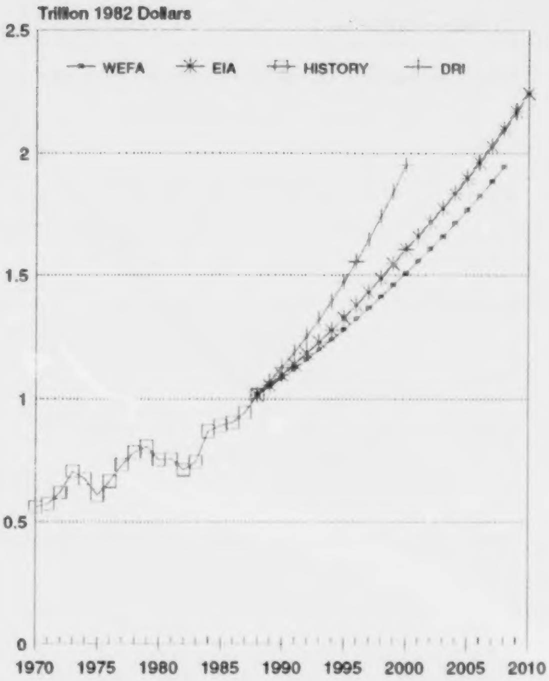


Figure 17. Agriculture Industry

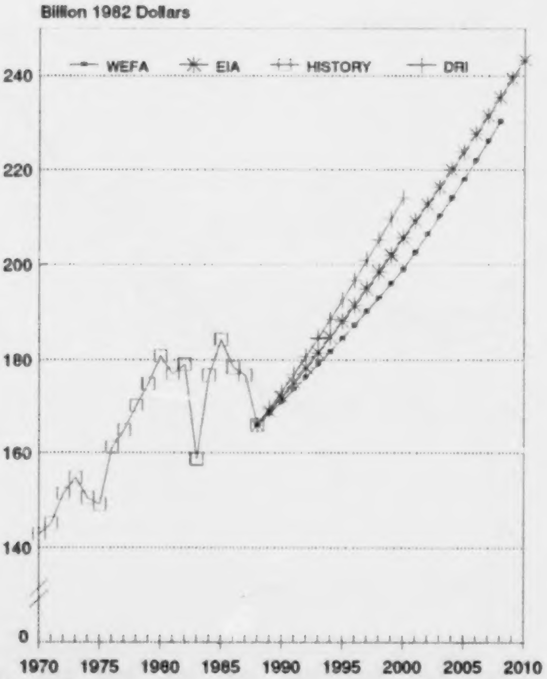
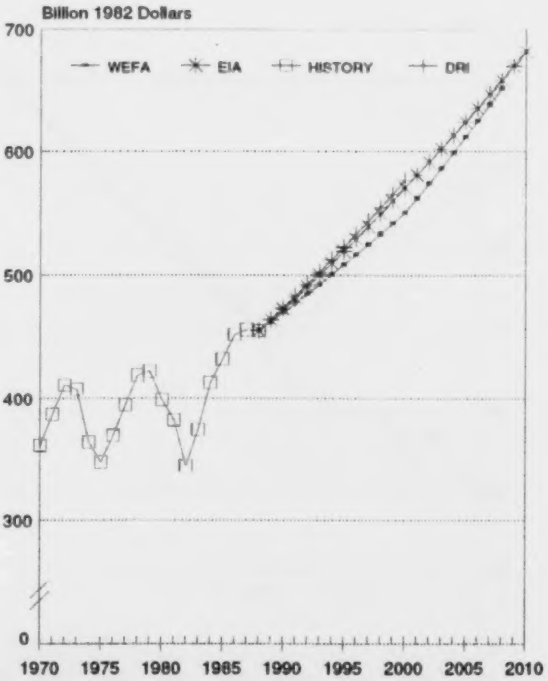


Figure 18. Construction Industry



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3. Demand Model Assumptions

Residential Sector

The residential sector model forecasts energy consumption in all residential structures (households) for three major energy sources: electricity, natural gas, and distillate; and for three minor fuels: kerosene, liquefied petroleum gas, and coal. Consumption is forecast as the product of the number of customers (houses that consume a particular fuel) and the average consumption per customer. The number of customers and their average consumption rates are assumed to depend upon variables such as fuel prices, personal income, population, and the mortgage rate of interest. The projection of residential energy consumption is based upon the latest Residential End Use Consumption Survey (RECS-87)[2] and engineering technology information provided under contract to the Office of Energy Conservation, DOE. Behavioral estimates of the effect of prices on consumption are based upon EIA analysis of the RECS-87 and fuel sales data. Appendix A presents a detailed description of residential sector technology assumptions.

Housing Assumptions

A total of 36 housing-type/vintage/location classes of homes are addressed:

- Single family, multi-family, and mobile homes
- Built 1974 and earlier, from 1975 to 1987, and after 1987
- Northeast, midwest, south, and west.

To better assess the effect of older homes on fuel demand, the pool of RECS homes was broken down into two groups. The periods 1974 and earlier, versus 1975 and later, represent the change when electricity replaced gas as the major heating fuel. It is also a natural break in the RECS-87[3] tabulations. All newer homes are treated as a third group of post-1987 homes, and these have the base characteristics of the average home built after 1980 in each Census region.

The rate of retirement for both homes and equipment is a dominant factor in determining consumption and conservation improvements. Based upon Census sample estimates, 0.3 percent of the homes are retired each year, with mobile homes having a higher retirement rate.

Energy services are estimated for each of the 36 classes of homes. These services include space heating, air-conditioning, water-heating, refrigeration and all other appliances (cooking, lighting and all other). Saturation limits for services in all homes and penetration rates for each class of home are estimated.

New housing starts based upon the DRI macroeconomic projections are relatively flat over the forecast period (with only 0.15 percent annual growth), reflecting demographic and economic trends, as shown in Figure 9. A projected decline in the number of households headed by persons between 25 and 34 years of age leads to a softening demand for rentals and a weaker demand on the low end of the housing market. Healthy demand continues in the mid-to-upper ranges of the housing market, supporting the overall growth in housing construction. New housing starts respond positively to the assumed rates of economic growth. Additional housing stock results in an increase in energy consumption. In the high economic growth case, new housing starts reach 1.76 million units by 2010; in the low economic growth case, new housing starts are 1.35 million units in 2010.

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[2] Energy Information Administration, *Household Energy Consumption and Expenditures 1987*, Part 1, "National Data" (Washington, DC, 1989).

[3] Energy Information Administration, *Housing Characteristics 1987* (Washington, DC, 1989).

The characteristics of newer homes are based upon those built in or later than 1980 by type and region from the RECS-87 data. These homes are considerably more efficient than older homes in that they demand less heat, but on average they include more air-conditioning. Overall appliance demand is also on average higher and as a result these homes are more electricity intensive.

Improvements in shell efficiency are based upon trends in RECS-87, and are assumed to be minimal; a nominal 0.5 percent improvement per year in pre-1975 single and multi-family homes is used to establish the base case.

Appliance characteristics for each Census region are estimated for a choice of new technologies for each service in its climate setting. There are eleven technology choices for heat (three electric heat pumps, three advanced gas furnaces, two distillate furnaces, one electric baseboard and two solar technologies) and six cooling technologies (three electric heat pumps and three electric air conditioners). There are five refrigeration technologies (all electric including vacuum panel) (Table A1 of Appendix A), four hot water technologies (two electric and two gas) (Table A2 of Appendix A), and finally an appliance technology mix to provide cooking, lighting and other fuel mixes.

Service demand estimates (in Btu) are provided for each service and class of home. Future energy consumption is a function of the technology characteristics of new appliances and the choice of new and replacement appliances.

Technology Choice

The technology choice calculation is sensitive to fuel prices. Given the input projection of Census region energy prices, a life-cycle cost calculation is made for each technology in each year and as a result the market share penetration is estimated for each technology for its particular service. In 1987 the market shares projected correspond to the aggregate equipment sales for major fuel types reported in the Census Department survey of home construction. Newer market technology shares are set relative to the base market share of the technology type, e.g., the market share of high efficiency heat-pumps is set equal to 5 percent of the market share for a standard heat-pump.

New technology fuel prices are the average predicted retail prices in each Census region. These are used to evaluate the life-cycle costs of a purchase assuming that the fuel price is fixed at its initial year value (the year of the choice) for a period of 5 years. A 20 percent real discount rate is applied to all forward costs (fuel and maintenance).

Census data[4] provide 1988 heat-pump/non heat-pump splits and main heating fuel shares. These shares are used to set the base technology initial share for the standard (lowest efficiency) heat-pump, the standard gas furnace, the standard air-conditioner and the standard water heaters. The technology shares for higher efficiency units are set at a nominal level (5 percent) to permit their penetration. The life-cycle cost calculation is normalized so that the 1988 initial shares are the market shares of each new technology. For later years relative changes in life-cycle costs permit any technology to increase or decrease its share of the market above or below the initial 1988 share.

Finally, actual technology penetration rates are estimated by Census region and service type. For replacement or new service capacity, the estimated new fuel share is an average of the current and possible new technology mix with a partial adjustment rate of 10 percent per year. This reflects not only market penetration of a new technology but also the average home-owners propensity to replace with equipment of similar fuel characteristics.

Changing fuel prices have two effects. First, higher fuel prices encourage the substitution of more fuel efficient technologies for existing technologies, where the same fuel is used. Second, higher fuel prices encourage fuel switching to alternative fuel-using technologies. These substitutions are modeled by a life-cycle cost analysis that selects technologies and fuels.

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[4] U.S. Department of Commerce, Bureau of Census, *Characteristics of New Housing: 1988*, C25-88-13 (Washington, DC, 1988), Table 10, p. 22.

Commercial Sector

The commercial sector consists of energy consumption in commercial buildings (such as offices, retail/wholesale buildings, institutions, and others). The projection of commercial sector energy consumption is based upon the latest Nonresidential Buildings Energy Consumption Survey (NBECS-86).[5] The COMMEND model,[6] that was developed by the Electric Power Research Institute, was also used in the calibration process. Appendix A presents a detailed description of commercial sector assumptions.

Energy requirements are estimated for seven building types, two vintages (existing and post-1986), and the four Census regions.

Building Assumptions

Six end-use services are addressed, including space heating, space cooling, water heating, cooking, lighting, and other. Changes in floor-space, improvements in shell and equipment efficiency, and the response to prices all affect the demand for these services.

Construction of new buildings is based on the recent historical pattern (by region and building type) indicated in the NBECS-86 data and adjusted by the corresponding rate of assumed employment growth for each region. After adjusting for attrition from existing stock, floorspace grows nationally at a rate of 1.9 percent per year in the base case, and ranges in value from 1.8 percent per year in the low macro case to 2.0 percent per year in the high macro case.

Overall service demand requirements (service demand per square foot) is assumed to change over time with changes in shell efficiency. Shell efficiency improves over the forecast period at a rate of 0.2 percent per year in existing buildings and 0.1 percent per year in newer buildings. Shell efficiency improvement rates were derived from regression analysis of NBECS data. Although the rates may appear to be relatively low when compared to some estimates of past rates of improvement, energy price escalation has slowed, and many of the more straight-forward conservation measures have already been taken.

Energy consumption for each service depends on the service demand, the level of macroeconomic activity and the weighted average efficiency of the equipment that is used to supply the service. New equipment additions are generally more efficient than the existing stock and cause average efficiency to improve over time.

Renewables are incorporated as a heat/hot water source, but they are not explicitly modeled as a separate technology in the commercial sector because of their relatively low market share. Exogenous estimates of current renewable use and future growth (discussed in the "Renewables" section of Chapter 4) are used to decrement demands for other energy services such as electricity and natural gas.

Technology Choice

New equipment choice considers life-cycle costs in deciding among alternative equipment types (fuels and efficiencies). New heating and cooling equipment operating patterns are based on the climate conditions for each region. Life-cycle cost components are developed from a review of research papers from a variety of government and private studies. The type of equipment selected is characterized by fuel source and efficiency. Observed new-product penetration rates are used to calibrate the rate of response to changes in relative life-cycle costs. Appendix A lists information sources.

The following technologies are evaluated in the equipment choice process for new service demands: heating (three gas furnaces, three oil furnaces and three electric heat pumps); cooling (three electric heat pumps and three electric air conditioners); water heating (two electric and two gas); and lighting (one incandescent and two fluorescent).

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[5] Energy Information Administration, *Nonresidential Buildings Energy Consumption Survey: Commercial Buildings Consumption and Expenditures 1986*, DOE/EIA-0318(86) (Washington, DC, May 1989).

[6] Electric Power Research Institute, *The COMMEND Planning System: National and Regional Data and Analysis*, EM-4486, Project 1216-6 (March 1986).

Over the forecast period, a gradual shift occurs in national patterns of end-use consumption. The use of electricity for heating gains due to a strong pace of construction in those regions where electric heat pumps are experiencing substantial gains in market share. Natural gas consumption for heating gains in absolute terms and relative to oil, but loses market share to electricity.

Effects of Fuel Prices

Changing fuel prices have two effects. If prices are raised there is an immediate estimated behavioral effect on consumption of that fuel for all services. Higher prices also change the life-cycle cost estimates for the different energy services to emphasize the choice of more efficient technologies. As a result, over time prices change the average characteristics of the various energy service technologies.

Higher fuel prices, due to alternative world oil price assumptions, affect life-cycle costs for each fuel using technology. Efficient technologies tend to be substituted for less efficient technologies, each using the same fuel. Also, technologies using relatively lower priced fuels are substituted for the expensive fuel.

Higher growth in employment, in the high growth macroeconomic case results in higher demand for each of the fuels.

Transportation Sector

The projection of energy consumption in the transportation sector is based upon the latest Residential Transportation Energy Consumption Survey (RTECS-88),[7] EIA's fuel consumption data,[8] and data from the Oak Ridge National Laboratory[9] on the composition of the transportation fleet and fuel efficiency. Consumption in this sector is almost completely in the form of oil. The oil consumption forecast is sensitive to the assumed level of macroeconomic activity as well as energy prices.

Personal Travel Assumptions

Growth in the stock of automobiles depends on affordability and replacement demand. Real income growth continues to keep automobiles affordable, coupled with relatively stable interest rates. However, growth in the automobile sector is limited by the projected age distribution of the population.

Energy consumption in this sector is the product of two, more detailed, estimates—new car fuel efficiency and the level of personal travel.

New car fuel efficiency as defined for corporate average fuel economy (CAFE) purposes, is forecast to grow at an average annual rate of 1.3 percent between 1988 and 2010, reaching a level of nearly 38 miles per gallon (mpg) in the base case. This value ranges from a low of about 34 miles per gallon in the low world oil price case to a high of nearly 41 miles per gallon in the high world oil price case. The corresponding range in new car fuel efficiency is between 0.8 and 1.7 percent. The average passenger car fleet efficiency, which reflects turnover in the existing stock, improves to approximately 28 miles per gallon in 2010 in the base case. In the low world oil price case the value is 25.5 mpg and in the high case it is 29.3 mpg. Following historical trends, new light truck fuel efficiency is forecast to grow at little more than half the new car rate, reaching a level of approximately 24 miles per gallon. New light truck fuel efficiency grows by between 21.9 and 26.5 miles per gallon in the low and the high world oil price cases.

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[7] Energy Information Administration, *Residential Transportation Energy Consumption Survey: Consumption Patterns of Household Vehicles 1985*, DOE/EIA-0464(88) (Washington, DC, April 1987).

[8] Energy Information Administration, *Annual Energy Review 1988*,DOE/EIA-0384(88) (Washington, DC, 1989).

[9] Oak Ridge National Laboratory, *Transportation Energy Data Book*, Edition 10, ORNL-6565 (Oak Ridge, TN, September 1989).

Achieved on-the-road efficiency, however, is assumed to remain below these CAFE-type estimates. It is assumed that the on-road miles per gallon will average 20 percent lower than EPA ratings of new car efficiency, based on current experience. While congestion and increased urbanization could tend to result in higher levels of degradation over time, it is assumed that reduced travel caused by such congestion and urbanization will serve to counterbalance this effect.

New car fuel efficiency estimates are based on the net savings consumers can realize if specific fuel efficiency improving technologies are introduced. Technologies that will save the consumer more in gasoline expenditures than they cost to purchase are assumed to be included in new car designs. Higher gasoline prices increase the forecast fuel efficiency because they increase gasoline expenditures without affecting the cost of available fuel efficiency-improving technologies. A 10 percent increase in gasoline prices above those assumed in the base case results in an initial short-term effect of a 2 percent improvement in new car fuel efficiency (reflecting a customer-response to the existing mix of new cars available for purchase) and a longer-term effect of a 6 percent improvement in fuel efficiency (reflecting a change in the mix of new cars available) if the price increase is sustained.

New technology car sales are assumed to be 10,000 in 1995 and to reach 80,000 in 2010, a minute portion of total sales. Non-oil based technologies do not play a major role in the forecast through 2010. The projected sales level is an assumption based on presumed economic feasibility.

Personal vehicle-miles traveled (VMT) is based on the assumed growth in disposable personal income and projected fuel prices. Personal VMT grows at an annual rate of 1.8 percent. VMT grows at a rate of 1.7 percent in the low world oil price case and 1.9 percent in the high world oil price case.

Alternate Fuels

Three alternate fuel technologies (methanol, compressed natural gas, and electricity) are assumed to begin penetrating the new car market gradually, beginning in the 1990's.

Methanol fuel, along with ethanol, derived from biomass is included in the base case. These biomass alcohols are blended directly and as components of ethers into gasoline. The total amount consumed depends upon the demand for gasoline in the transportation sector. A final base case estimate had biomass alcohol consumption at 0.06 quads in 1988 and 0.26 quads in 2010.

Freight Travel Consumption

Freight vehicles consume about 30 percent of the transportation sectors' forecast oil consumption in 1990. It is assumed that the average efficiency of freight trucks improves at a rate of 1.1 percent per year and that freight trucks increasingly are powered by diesel engines. The diesel share reaches 60 percent by 2010. Other freight vehicles are not assumed to show significant improvements in fuel efficiency.

Travel by freight vehicles is closely tied to the level of output in specific sectors of the economy. Freight truck vehicle-miles traveled is forecast to grow at an average annual rate of between 1.8 and 2.3 percent per year.

Aviation Travel Consumption

Air travel represents the fastest growing mode of travel over the forecast period, increasing at an average annual rate of about 3.6 percent. Forecasts of air travel are highly sensitive to assumed levels of economic growth. Jet fuel prices also affect the level of air travel through their effect on ticket prices. Aircraft fuel efficiency is assumed to improve at an annual rate of 1.9 percent between 1988 and 2010. This growth rate is based on the assumption that new generation aircraft use the best available technology and that 747's and 767's retire after 20 years service. No efficiency improvements are assumed for the existing stock of aircraft. Alternative assumptions could be examined in different scenarios.

Industrial Sector

The industrial model forecasts energy consumption for fuel (heat and power) and nonfuel (feedstock and miscellaneous) uses in the manufacturing, agriculture, mining and construction industries. The consumption of energy for fuel and electrical uses is estimated from time-series data (The National Energy Accounts[10] from the Department of Commerce) over the period 1958 through 1985 (the manufacturing sector data in this time-series for 1985 is EIA's Manufacturing Energy Consumption Survey).[11] The estimation of nonfuel use of energy is from various sources, depending upon the availability of data.

The industrial model scenarios are produced by running the industrial model using the high and low world oil price scenario exogenous price forecasts produced by the supply models and using the high and low macroeconomic scenario exogenous macroeconomic forecasts produced by the macroeconomic model. In addition, different exogenous forecasts of nonutility generation and of coal synthetics are used by the industrial model.

Manufacturing Demand

The rate of overall industrial growth, and the growth in each component sector, is linked integrally with the size and configuration of the macro economy. Personal expenditures on consumer items is expected to decline as a share of GNP. A larger share of the GNP is devoted to the production of goods going into investment and export categories of final demand. As a result, manufacturing output is expected to grow at an average annual growth rate of 2.8 percent through 2010. Since the macro economy is configured differently in the low and high economic growth cases, industrial production growth rates vary among economic growth cases. Manufacturing output annual growth rates range from 2.3 percent in the low growth case to 3.2 percent in the high growth case.

The manufacturing heat and power sector consists of industries in SIC codes 30 through 39 and is subdivided into the following eight separate groups of industries: Chemicals, Rubber and Plastic (SIC codes 28 and 30), Primary Metals (SIC code 33), Food (SIC code 20), Paper (SIC code 26), Metal Durables (SIC codes 34 through 38) and Other (SIC codes 21 through 25 and 27, 31 and 39). A base forecast of energy consumption is determined for purchased electricity, natural gas, steam coal, residual oil, distillate oil, liquefied petroleum gas, still gas, petroleum coke and coking coal. The base forecast of energy consumption is determined for each fuel in each industry based upon estimated historical relationships (over the period 1958 through 1985 from the National Energy Accounts and the Manufacturing Energy Consumption Survey) between energy consumption and the prices of each energy source in the industry and the value of the goods produced in the industry.

Production of machinery (SIC 34-38) is forecast to rise the fastest (3.7 percent per year through 2010 in the base case), fundamentally driven by investment and export related demand. The largest component of growth within this sector is office equipment, including computers. In the low and high economic cases, the annual growth rate of production in machinery equipment varies from 3 percent to 4.3 percent.

Production within the primary metals sector (SIC 33) is forecast to show a moderate rebound (1.3 percent annual growth) from the slow to negative growth of the 1980's. The recovery is primarily in the production of higher value-added products as opposed to raw, unprocessed basic commodities. Production in primary metals industry in the low and high economic growth cases range from 0.8 percent annual growth to 1.8 percent annual growth.

Production in the chemical and plastic sectors (SIC 28 and SIC 30) is forecast to show steady growth over the forecast period (3.0 percent annual growth). Much of the growth in these sectors is also export driven. In the low and high economic growth cases the annual growth rate of the chemical and plastics sector range from 2.6 percent to 3.4 percent.

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[10] The National Energy Accounts database is documented in the U.S. Department of Commerce, Office of Business Analysis, *National Energy Accounts*, PB89-187918 (Washington, DC, February 1989).

[11] Energy Information Administration, *Manufacturing Energy Consumption Survey: Consumption of Energy 1985*, DOE/EIA-0512(85) (Washington, DC, November 1988).

Nonmanufacturing Demand

The nonmanufacturing heat and power sector consists of industries in SIC codes 1 through 17 and is subdivided into the following three separate groups of industries: Agriculture (SIC codes 1 through 9), Mining (SIC codes 10 through 14) and Construction (SIC codes 15 through 17). A base forecast of energy consumption is determined for purchased electricity, natural gas, steam coal, residual oil, distillate oil, liquefied petroleum gas and motor gasoline. The base forecast of energy consumption is determined for each fuel in each industry based upon estimated historical relationships (during the period 1958 through 1985) between energy consumption and the prices of each energy source in the industry and the value of the goods produced in the industry.

Manufacturing sector energy consumption for feedstock (raw materials and miscellaneous nonfuel uses) is modeled separately from heat and power uses. Natural gas feedstocks, liquid gas feedstocks and petrochemical feedstocks are assumed to be related to the value of the final goods produced in the chemical industry and to natural gas prices, liquid gas prices and residual oil prices (as a proxy), respectively. Asphalt and road oil is assumed to be related to the value of production in the construction industry and to residual oil prices (as a proxy). Small amounts of other nonfuel energy consumption are assumed to remain at their initial levels.

All the forecasting equations and other pieces of the model are calibrated and reconciled in 1985 to the Manufacturing Energy Consumption Survey for manufacturing heat and power, to the National Energy Accounts for nonmanufacturing heat and power and overall to the State Energy Database System.[12] The dynamics in the equations are calibrated to follow their respective patterns during the period 1980 through 1985.

A review of the forecast of natural gas use for manufacturing heat and power as compared to the historical data revealed that there was a small efficiency trend which was not captured by the forecasting equations. The model can implement efficiency time trends which reflect these additional expections of efficiency improvements above those captured in the specification of the estimated equations. This additional efficiency improvement was implemented for natural gas.

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[12] Energy Information Administration, *State Energy Data Report: Consumption Estimates 1960-1987*, DOE/EIA-0214(87) (Washington, DC, April 1989).

4. Supply Model Assumptions

Crude Oil, Natural Gas Supply, and Natural Gas/Petroleum Product Pricing

The PC Oil and Gas Spreadsheet (OGS) model of the PC-AEO modeling system represents aggregate domestic crude oil and natural gas production and natural gas pricing for the *AEO*. The OGS model reads in world oil prices and natural gas demand by end-use sector, and then calculates domestic crude oil and natural gas production as well as the wellhead price of natural gas for 1990 through 2010. National average wellhead prices of natural gas for each of the five *AEO* scenarios and the values for net imports of natural gas are assumed in the OGS based upon exogenous analyses. Then the wellhead price of natural gas is added to user defined markups to obtain end-use prices for natural gas by sector. The OGS characterizes the most significant national trends of U.S. oil and natural gas production and natural gas pricing, as modeled by the Production of Onshore Lower 48 Oil and Gas Model[13] and the Gas Analysis Modeling System.[14]

The Oil Market Module (OMM) of PC-AEO computes end-use prices of seven petroleum product categories, by sector and region, and the overall petroleum supply/disposition balance. World oil prices, petroleum product demands, as well as domestic oil production are used as inputs to OMM. Domestic refinery production is derived from product demands by netting out the other supply components such as natural gas liquids used as blending components. The resulting production volumes are then used as inputs to five refinery gate equations, from which the petroleum product end-use prices are derived.

Specific model computations and the values and sources for the model parameters are described in the model documentation. Unless otherwise noted, the assumptions presented are characteristic of the high and low economic and world oil price cases as well as the base case. The following section highlights those analytical and methodological assumptions that were particularly important in obtaining the results presented in the *AEO*.

Crude Oil Production

Lower 48 onshore conventional oil production is based upon United States Geological Survey (USGS)[15] undiscovered recoverable resource estimates of 16.8 billion barrels and EIA estimates of proved reserves of 16.6 billion barrels at the end of year 1988. The undiscovered resources are USGS estimates, as of December 31, 1986, adjusted according to 1987 and 1988 EIA-23 reserve additions. Reserve revisions are an assumed average of several years of historical revision data. Other fundamental data used for the projection of production include drilling costs, drilling activity, reserves, production profiles, and average well depths. All computations are done at the level of 6 onshore regions. Exploratory drilling is computed by an econometric function of the assumed world oil price and translates that into reserve additions, via an exponentially declining finding rate function. The level of developmental drilling is computed through a discounted cash flow analysis of the expected returns to future production. The discount rate used for the discounted cash flow analysis was 10 percent.

The role of unconventional oil, such as heavy oil, tar sands, bitumen, and enhanced oil recovery (EOR) increases from now until the end of the projection period. However, no dramatic changes are expected to occur until prices reach the high end of the price range for 2010. Alternative technologies such as oil shale and synfuels are not expected to contribute significantly until this happens.

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[13] Energy Information Administration, *Model Methodology and Data Description of the Production of Onshore Lower 48 Oil and Gas Model*, DOE/EIA-M034.

[14] Energy Information Administration, *Model Documentation of the Gas Analysis Modeling System*, DOE/EIA-0450.

[15] United States Geological Survey, Minerals Management Service, *Estimates of Undiscovered Conventional Oil and Gas Resources in the United States* (Washington, DC, 1989).

Estimates of enhanced oil recovery (EOR) are based upon the latest National Petroleum Council (NPC) study,[16] published in 1984. This study provided an estimate of 19.0 billion barrels of oil producible using EOR techniques and also provided production forecasts for several assumed oil price paths. EIA forecasts EOR production using an interpolation technique on the NPC production estimates, relative to its own assumed prices.

Undiscovered recoverable oil resources from the Lower 48 Federal offshore region were 12.7 billion barrels, the USGS estimate as of December 31, 1986, with end-of-year reserves in 1988 of 3.2 billion barrels. The production was estimated by using historical decline rates for existing production, combined with a drilling model that estimated new production using assumed drilling rates.

Inferred/indicated reserves of oil in the Lower 48 are 20.8 billion barrels measured at the end of 1986.

Undiscovered recoverable resource estimates of oil in Alaska measured roughly 16.6 billion barrels, as of December 31, 1986, according to the USGS, with end-of-year reserves in 1988 of 7.0 billion barrels. EIA projects Alaskan production on a field-level analysis of known areas, incorporating assumptions of the likely maximum production potential and decline rates. Production from the coastal plain of the Arctic National Wildlife Refuge (ANWR) is excluded because it is currently not permitted under existing law.

Natural Gas Production and Price

The average wellhead price of domestic natural gas is determined by the market equilibration between the supply and demand of gas, as represented by the Gas Analysis Modeling System. The five wellhead price paths were computed by executing the model, using the demands for natural gas for each of the five scenarios.

Natural Gas Wellhead Prices ($89/mcf)	1990	1995	2000	2005	2010
Mid Oil Price, Mid Macro	1.81	2.25	3.23	4.36	5.63
Low Oil Price, Mid Macro	1.61	2.14	3.03	3.83	4.59
High Oil Price, Mid Macro	1.95	2.20	3.11	4.18	5.51
Mid Oil Price, Low Macro	1.79	1.93	2.86	3.61	4.57
Mid Oil Price, High Macro	1.82	2.56	3.78	4.87	6.09

Lower 48 onshore conventional gas production is based upon EIA-23 adjusted USGS undiscovered recoverable resource estimates for non-associated gas of 218.5 trillion cubic feet at the beginning of year 1989. EIA estimates total dry natural gas proved reserves in the Lower 48 onshore region to be 124.7 trillion cubic feet at the end of year 1988, of which associated-dissolved natural gas reserves are 18.3 trillion cubic feet. Reserve revisions are an assumed average of several years of historical revision data. Other fundamental data used for the projection of production include drilling costs, drilling activity, reserves, production profiles, and average well depths. All computations are done at the level of 6 onshore regions. Exploratory drilling is computed by an econometric function of the average wellhead price of gas and translates that into reserve additions, via an exponentially declining finding rate function. The level of developmental drilling is computed through a discounted cash flow analysis of the expected returns to future production. The discount rate used for the discounted cash flow analysis was 10 percent.

Forecasts of Lower 48 onshore unconventional gas production are based upon resource estimates of 146 trillion cubic feet of undiscovered economically recoverable resources, derived from United States Department of Energy, *An Assessment of the Natural Gas Resource Base of the United States*, May 1988. This gas is expected to come from low-permeability formations, Devonian shale, and coalbed methane. The phrase "economically recoverable" is used to identify the subset of the overall resource base that is most relevant for supply projections. Economically recoverable resources are considered reserves only after discovery and certification as producible.

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[16] National Petroleum Council, *Enhanced Oil Recovery* (Washington, DC, June 1984).

Associated-dissolved natural gas production is computed as a co-product of Lower 48 crude oil production.

Undiscovered recoverable gas resources from the Lower 48 Federal offshore region have been estimated at 128.3 trillion cubic feet by the USGS as of December 31, 1986. End-of-year reserves in 1988 measured 34.3 trillion cubic feet of dry natural gas.

Inferred/indicated reserves of natural gas in the Lower 48 are 95.8 trillion cubic feet, measured at the end of 1986.

Currently about 30 trillion cubic feet of natural gas recoverable resources are located on the Alaskan North Slope. Undiscovered technically recoverable resources of natural gas in Alaska have been estimated at 74.7 trillion cubic feet as of December 31, 1986, by the USGS. Production levels of 2.3 billion cubic feet per day, or 840 billion cubic feet per year, could be achieved, with possible expansion to 3.5 billion cubic feet per day according to announced pipeline construction plans. Alaskan gas is assumed to be economic and available when the wellhead price of Lower 48 supplies reaches approximately $4.20 per thousand cubic feet, in 1989 dollars, with the expansion occurring when the price reaches approximately $5.40 per thousand cubic feet. Under this condition, Alaskan gas begins flowing to the Lower 48 States by 2005 in the base case forecast. Natural gas production from the ANWR is excluded from the forecast because existing legislation prohibits it.

Synthetic natural gas (SNG) produced from petroleum liquids is based on the relative domestic natural gas wellhead price and the assumed world oil price. SNG from coal gasification reflects full utilization of the capacity of the Great Plains facility of 50 billion cubic feet, which is assumed to expand by 50 percent in 2005 in the base case and in 2002 in the high oil price case.

Gas and Oil Imports

Net natural gas imports are projected to reach approximately 2.95 trillion cubic feet by the year 2010 in the base case. Of this flow, approximately 2 trillion cubic feet are imports from Canada, 0.25 trillion cubic feet are from Mexico, and the remaining imports are from liquefied natural gas (LNG).

Net Pipeline Imports (tcf)	1990	1995	2000	2005	2010
Mid Oil Price, Mid Macro	1.358	1.684	2.125	2.225	2.225
Mid Oil Price, Low Macro	1.358	1.623	1.873	2.025	2.025
Mid Oil Price, High Macro	1.358	1.684	2.160	2.325	2.425

Under base case assumptions, pipeline imports from Mexico resume at a level of 150 billion cubic feet in 1999, increasing to 250 billion cubic feet in 2003. In the low macroeconomic growth case, the imports resume in 2004 at 150 billion cubic feet. In the high growth cases, the imports enter at 150 billion cubic feet in 1998, increasing to 250 billion cubic feet in 2003 and to 350 billion cubic feet in 2008. All four LNG terminals are assumed to be reactivated, with LNG imports allowed to the extent that they do not exceed in-place terminal capacity. Current terminal capacity is approximately 920 billion cubic feet. A capacity factor of 75 percent is assumed for the Distrigas terminal and of 85 percent for the other three terminals in the base case. The high macro growth case assumes expansion of the Lake Charles facility by 110 billion cubic feet.

Liquefied Natural Gas Imports (bcf)	1990	1995	2000	2005	2010
Mid Oil Price, Mid Macro	75	382	535	722	722
Mid Oil Price, Low Macro	75	353	490	638	638
Mid Oil Price, High Macro	75	426	645	813	813

Net crude oil imports are calculated as the difference between total product supplied for domestic use and the sum of crude oil production, net product imports, natural gas liquids and other domestic production including petroleum production from coal, refinery processing gain and net primary stock withdrawals. Net petroleum product imports are derived by applying the 1988 share of domestic product demand that was supplied by net imports to the product demands throughout the forecast period. The shares are as follows:

Distillate Fuel	7	Percent of 1988 Distillate Demand
Residual Fuel	32	Percent of 1988 Residual Demand
Liquefied Petroleum Gases	10	Percent of 1988 Liquefied Petroleum Gases Demand
Motor Gasoline	5	Percent of 1988 Motor Gasoline Demand
Jet Fuel	4	Percent of 1988 Jet Fuel Demand
Petrochemical Feedstocks	27	Percent of 1988 Petrochemical Feedstocks Demand
Other Products	12	Percent of 1988 Other Products Demand

Crude oil exports are calculated by a function of the world oil price and Alaskan crude oil production. Total product exports are a function of total domestic petroleum demand. These relationships implicitly assume that no constraints on imports exist and that the decision to import product or produce it in the United States will not lead to any changes in profits for either method of supply.

Refinery and Transport Capacity

U.S. refinery capacity, 15.7 million barrels per day as of January 1, 1989, is assumed to "change as needed" during the forecast period and applies to upstream as well as downstream capacity. It is implicitly assumed that the refinery capacity levels dictated by petroleum product demand and price forecasts will be appropriate in the years they are required and will be of the type of capacity needed to meet the changing environmental standards for refined products. Base case forecasts of steady growth in petroleum demand combined with relatively slow growth in product imports result in an implicit forecast of steady necessary growth in U.S. refinery capacity during the next 20 years.

U.S. petroleum transportation capacity is not explicitly addressed in these forecasts. The capacity of the transportation system is implicitly assumed to be adequate to meet any requirements imposed by supply and demand levels. Transportation costs are implicitly included in the model in the markups of prices. Any transportation constraints would be reflected in upward pressures on prices.

Natural gas pipeline capacity is assumed to be adequate to meet demand through 2010, either from existing capacity or from assumed new construction. The costs of any new transmission capacity are captured in the pipeline transportation tariffs.

Gas and Oil End-Use Prices

End-use markups for petroleum products and natural gas are estimated by adding a regional markup to the national refinery gate price for each petroleum product and by adding a regional markup to the national wellhead price of natural gas. For petroleum products, the markups represent the actual average regional and sectoral markups between 1984 and 1988 and are then held constant throughout the forecast period. The table below presents the markups in 1989 dollars per million Btu.

Petroleum Product Markups by Sector and Census Region
(1989 Dollars per Million Btu)

Product	Sector	Census Region			
		1	2	3	4
Gasoline	Commercial	2.87	2.92	2.75	2.88
Gasoline	Industrial	2.88	2.96	2.73	2.88
Gasoline	Transportation	2.96	2.97	2.80	2.93
Distillate Fuel	Residential	2.59	1.86	2.47	1.97
Distillate Fuel	Commercial	0.85	0.28	0.20	0.10
Distillate Fuel	Industrial	0.65	0.58	0.42	0.42
Distillate Fuel	Transportation	3.68	3.38	2.95	3.35
Distillate Fuel	Electric Utility	0.27	0.28	0.04	0.48
Residual Fuel	Commerical	0.75	0.19	0.27	0.04
Residual Fuel	Industrial	0.67	0.05	0.37	-0.27
Residual Fuel	Transportation	0.22	0.58	-0.33	0.13
Residual Fuel	Electric Utility	0.42	0.81	0.24	0.86

Petroleum Product Markups by Sector and Census Region
(1989 Dollars per Million Btu)
(Continued)

Product	Sector	Census Region 1	2	3	4
Liquefied Petroleum Gases	Residential	7.25	4.59	6.81	6.68
Liquefied Petroleum Gases	Commerical	8.18	5.19	5.74	5.22
Liquefied Petroleum Gases	Industrial	7.46	5.12	2.99	5.52
Liquefied Petroleum Gases	Transportation	7.78	5.25	5.48	5.65
Jet Fuel	Transportation	0.11	0.15	-0.03	0.27
Petrochemical Feedstocks	Industrial	0.00	0.00	0.00	0.00
Other	Residential	3.91	3.26	3.21	4.91
Other	Commerical	0.96	1.09	0.82	2.80
Other	Industrial	0.34	0.33	0.29	0.26
Other	Transportation	3.09	3.04	3.19	3.17
Other	Electric Utility	0.43	0.41	0.43	0.43

The natural gas markups generally consist of a gathering charge, pipeline markup for long-distance transmission, and a distributor markup for local distribution of the gas. The tables presented below display the markups for each of the end-use sectors and Census regions for the five scenarios. These aggregate transmission and distribution markups were derived by computing the quantity-weighted average markup from the ten Federal regions forecast generated by the Gas Analysis Modeling System.

The rate design representation of the Gas Analysis Modeling System is essentially cost-based. It does include a component to represent the more flexible rate designs, recently promoted by the Federal Energy Regulatory Commission, that encourage increased competition. Pipeline and distributor tariffs are derived from annual data from the following surveys: Form EIA-176, Form EIA-857, and Form FERC-2. Cost-based and market competitive markups were estimated and used in generating the base case forecast, subject to selective discounting down to the commodity cost of the gas to maintain those markets capable of switching to alternative fuels. The tariffs in the low oil price case reflect the results of the discounting evident in the base case and include a 5 percent reduction in the residential, commercial, and industrial sector markups. This reduction reflects the reduction of the component costs and the increased competitive pressures. Conversely, in the high case, the residential, commercial, and industrial sector markups were increased 5 percent above base case levels.

Natural Gas End-Use Markups by Sector and Census Region
(1989 Dollars per Million Btu)

Mid Oil Price, Mid Macro	1990	1995	2000	2005	2010
Residential, Region 1	3.52	3.70	3.71	3.70	3.70
Residential, Region 2	2.52	2.62	2.62	2.62	2.62
Residential, Region 3	2.93	3.10	3.10	3.10	3.10
Residential, Region 4	2.87	3.03	3.03	3.03	3.02
Commercial, Region 1	2.90	2.94	2.95	2.94	2.94
Commercial, Region 2	2.15	2.14	2.14	2.14	2.13
Commercial, Region 3	2.28	2.35	2.35	2.35	2.34
Commercial, Region 4	2.18	2.24	2.25	2.25	2.24
Industrial, Region 1	1.80	1.65	1.68	1.66	1.57
Industrial, Region 2	1.61	1.52	1.54	1.54	1.49
Industrial, Region 3	0.58	0.53	0.54	0.53	0.51
Industrial, Region 4	1.56	1.46	1.48	1.47	1.40
Electric Utility, Region 1	0.51	0.52	0.53	0.52	0.29
Electric Utility, Region 2	0.20	0.41	0.45	0.44	0.44
Electric Utility, Region 3	0.36	0.38	0.39	0.39	0.27
Electric Utility, Region 4	0.95	0.95	0.94	0.91	0.69

Natural Gas End-Use Markups by Sector and Census Region
(1989 Dollars per Million Btu)
(Continued)

Low Oil Price, Mid Macro	1990	1995	2000	2005	2010
Residential, Region 1	3.52	3.61	3.52	3.51	3.51
Residential, Region 2	2.52	2.56	2.49	2.49	2.49
Residential, Region 3	2.93	3.01	2.93	2.93	2.93
Residential, Region 4	2.87	2.95	2.88	2.87	2.87
Commercial, Region 1	2.90	2.87	2.79	2.79	2.79
Commercial, Region 2	2.15	2.09	2.03	2.03	2.03
Commercial, Region 3	2.28	2.29	2.23	2.23	2.23
Commercial, Region 4	2.18	2.19	2.13	2.13	2.13
Industrial, Region 1	1.63	1.52	1.52	1.52	1.52
Industrial, Region 2	1.61	1.51	1.47	1.47	1.46
Industrial, Region 3	0.58	0.54	0.52	0.52	0.52
Industrial, Region 4	1.56	1.48	1.44	1.44	1.44
Electric Utility, Region 1	0.51	0.48	0.45	0.45	0.45
Electric Utility, Region 2	0.20	0.35	0.35	0.35	0.35
Electric Utility, Region 3	0.36	0.34	0.34	0.34	0.34
Electric Utility, Region 4	0.95	0.80	0.83	0.81	0.80

High Oil Price, Mid Macro	1990	1995	2000	2005	2010
Residential, Region 1	3.52	3.79	3.89	3.89	3.89
Residential, Region 2	2.52	2.69	2.76	2.76	2.75
Residential, Region 3	2.93	3.16	3.25	3.25	3.24
Residential, Region 4	2.87	3.10	3.18	3.18	3.18
Commercial, Region 1	2.90	3.01	3.09	3.09	3.09
Commercial, Region 2	2.15	2.19	2.25	2.25	2.24
Commercial, Region 3	2.28	2.40	2.47	2.47	2.47
Commercial, Region 4	2.18	2.30	2.36	2.36	2.36
Industrial, Region 1	1.80	1.80	1.80	1.80	1.80
Industrial, Region 2	1.61	1.59	1.63	1.63	1.62
Industrial, Region 3	0.58	0.56	0.58	0.58	0.58
Industrial, Region 4	1.56	1.55	1.59	1.59	1.59
Electric Utility, Region 1	0.51	0.52	0.53	0.53	0.53
Electric Utility, Region 2	0.20	0.54	0.60	0.60	0.60
Electric Utility, Region 3	0.36	0.39	0.39	0.39	0.38
Electric Utility, Region 4	0.95	0.95	0.94	0.91	0.88

Mid Oil Price, Low Macro	1990	1995	2000	2005	2010
Residential, Region 1	3.52	3.70	3.70	3.70	3.70
Residential, Region 2	2.52	2.62	2.62	2.62	2.62
Residential, Region 3	2.93	3.10	3.10	3.10	3.10
Residential, Region 4	2.87	3.03	3.03	3.03	3.03
Commercial, Region 1	2.90	2.94	2.94	2.94	2.94
Commercial, Region 2	2.15	2.14	2.14	2.13	2.14
Commercial, Region 3	2.28	2.35	2.35	2.35	2.35
Commercial, Region 4	2.18	2.24	2.25	2.24	2.25
Industrial, Region 1	1.80	1.68	1.75	1.75	1.74
Industrial, Region 2	1.61	1.53	1.55	1.54	1.54
Industrial, Region 3	0.58	0.53	0.55	0.54	0.55
Industrial, Region 4	1.56	1.48	1.51	1.51	1.51

Natural Gas End-Use Markups by Sector and Census Region
(1989 Dollars per Million Btu)
(Continued)

Electric Utility, Region 1	0.51	0.52	0.53	0.53	0.53
Electric Utility, Region 2	0.20	0.40	0.43	0.43	0.43
Electric Utility, Region 3	0.36	0.39	0.39	0.38	0.38
Electric Utility, Region 4	0.95	0.95	0.94	0.92	0.91

Mid Oil Price, High Macro	1990	1995	2000	2005	2010
Residential, Region 1	3.52	3.70	3.70	3.70	3.70
Residential, Region 2	2.52	2.62	2.62	2.62	2.62
Residential, Region 3	2.93	3.08	3.08	3.08	3.09
Residential, Region 4	2.87	3.03	3.02	3.02	3.03
Commercial, Region 1	2.90	2.94	2.94	2.94	2.94
Commercial, Region 2	2.15	2.14	2.13	2.13	2.14
Commercial, Region 3	2.28	2.34	2.34	2.34	2.35
Commercial, Region 4	2.18	2.24	2.24	2.24	2.25
Industrial, Region 1	1.80	1.79	1.79	1.79	1.80
Industrial, Region 2	1.61	1.55	1.54	1.54	1.54
Industrial, Region 3	0.58	0.55	0.55	0.55	0.55
Industrial, Region 4	1.56	1.51	1.51	1.51	1.51
Electric Utility, Region 1	0.51	0.47	0.47	0.48	0.49
Electric Utility, Region 2	0.20	0.34	0.35	0.35	0.35
Electric Utility, Region 3	0.36	0.36	0.36	0.36	0.37
Electric Utility, Region 4	0.95	0.79	0.79	0.76	0.72

Coal Supply and Pricing

Coal market projections of coal supply and prices presented in the 1990 *AEO* were developed with the AEO-PC Coal Price and Supply Model (COAL).[17] The major assumption underlying the methodology of the COAL model is that given a level of demand for coal, coal producers will provide the necessary level of supply to meet the demand, where supply is defined as the sum of domestic production, net imports and storage adjustments. A detailed presentation of coal assumptions is provided in Appendix B.

It is assumed that there are no capacity constraints on coal producers over the forecast period given current levels of reserves and the capacity of the transportation system. Production is assumed to be able to meet projected domestic demands and exports. This assumption refers to coal production, and not to production of alternative fuels which might be derived from coal, such as methanol. Separate assumptions in the appropriate demand sections are made with respect to such capacity.

Coal Pricing

Delivered prices of coal are assumed to be the sum of minemouth costs and transportation markups.

It is assumed that minemouth prices of coal are determined by their historic relationship to the quantity of production, labor productivity, and natural gas prices at the wellhead. A corollary assumption is that the fuel which competes most directly with coal, especially at the point of consumption, is natural gas. It is assumed that this competition will continue through the forecast period. It is also assumed that the level of coal prices will vary in the forecast period by region, based on historical differentials. No specific assumption on price differentials by sulfur content are made, but the use of historical data implicitly assumes that those differentials will continue through the forecast horizon. Table B1 of Appendix B shows the estimated parameters for the equation which defines the relationship.

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[17] Energy Information Administration, *PC-AEO Forecasting Model for the Annual Energy Outlook 1990*, DOE/EIA-M036 (Washington, DC, March 1990).

In the base case, labor productivity in the coal industry is assumed to increase 1 percent annually through 2000, and 0.5 percent annually from 2001 through 2010. This assumption is based upon a long-term examination of productivity trends and their relationship to changes in laws and regulations, structural changes, and technological change. It is assumed that there will be no major changes in these factors during the forecast period in the base case. In particular, it is assumed that penetration of longwall mining systems will not increase at as high a rate over the forecast period as it has in the 1980's, since opportunities for cost savings are leading to market saturation. And it is assumed that the high rate of closing of smaller, less efficient mines seen in the 1980's will slow significantly, since so few of those mines are now producing coal. Productivity by region by year is shown in Table B5 of Appendix B.

Transportation markups are assumed to be determined by their current (as of 1988) level, escalated by the rail transportation index escalator. That escalator, which is exogenous to the model, is in turn assumed to be determined by its historical relationship to wages, equipment costs, and fuel costs. Table B2 of Appendix B provides the index escalators and their associated input variables and Table B3 shows the markups.

Coal Supply

It is assumed that the distribution patterns for coal (from supply region to demand region/sector) will continue their 1980 through 1988 trends throughout the forecast period, but at a slower rate of change. The changes in distribution shares between 1988 and 2010 are assumed to approximate the changes experienced between 1980 and 1988. It is further assumed that the changing costs of developing mines and extracting coal will not significantly affect these patterns. The assumed pattern is displayed in Table B4 of Appendix B.

Producer and consumer stocks of coal are assumed to remain at constant days of supply (calculated as of the end of 1990) throughout the forecast period. Production of coal is assumed to be adjusted to maintain this equality.

Coal exports and imports are assumed to be determined exogenously, through the International Coal Trade Model.

Coal quality (in terms of heat content per ton) is assumed to remain constant from given supply regions over the forecast period. For utility coal, specific heat values are assigned to each supply region based on the most recent data. For other sectors, the quality of coal received by a particular demand region/sector is assumed to be the same from all supply regions. This is because for nonutility coal, the only quality data available is for receipts. It is assumed that the opening of new mines will keep aggregate quality constant, while quality of coal produced at existing mines will decline somewhat as a natural result of the mining process. Assumed heat content by sector by year is shown in Table B6 of Appendix B.

Renewables

Renewable Energy is defined as Wind, Ocean Thermal, Photovoltaics, Geothermal, Hydroelectric, Biomass, Alcohol Fuels, Solar Thermal, and Solar Buildings. Assumptions presented here are characteristic of the base case only.

Renewable Energy is estimated for the following applications:

- Electricity Generation by Electric Utilities
- Nonutility Generated Electricity Sold to Grid
- Nonutility Generated Electricity for Self Use
- Uses at Dispersed Sites Other Than Electricity Generation.

Renewable Energy is modeled as a supply source for the first two applications listed above. Renewable Energy is modeled as a decrease in demand for the last two applications listed above.

Estimates of Renewable Energy contributions are provided for the 10 Federal Regions.

Estimates of the life-cycle cost of each renewable technology, the expected costs of conventional sources of energy, the projected demand, and judgment are used to determine the actual penetration of each renewable technology.

Following is a summary of the national contribution of renewable energy sources that have been projected.

Assumptions of Renewable Energy Forms

End Use Sectors (Residential, Commercial, Industrial, and Transportation)

Solar Thermal, Passive, Solar, and Daylighting: Detailed assumptions are documented in *Assessment of the Contribution of Renewable and Nuclear Energy to National Energy Supplies*, Science Applications International Corporation (December 1989.)

Installed cost per unit of design capacity for solar thermal technology declines by about 50 percent between 1990 and 2000.

Market penetration is based on payback period ranging from 100 percent penetration for 1-year payback to 30 percent penetration for 7-year payback in the residential sector.

For Biofuels moderate growth is assumed through the year 2005 after which the availability of waste wood is anticipated to reach a saturation level, with new short-rotation wood dedicated to liquid fuels production. The projections are 14, 47, 19, and 19 percent for the Northeast, South, Midwest, and West regions, respectively.

Future regional distribution is proportional to current distribution of biofuels production capacity.

Alcohol use is in the form of octane enhancers and oxygenates for blending into gasoline, with ethanol (produced from corn) capturing less than 2 percent of the market for blended gasolines substituted with motor gasoline.

Hydropower assumes no retirements of existing plants.

Ownership of projected hydropower is 30 percent for private (investors, individuals, industrial), 14 percent for private utilities, 17 percent for Federal utilities, and 39 percent for non-Federal public agencies.

Low growth in capacity is assumed due to resource limitations, and environmentally-constrained site availability.

For Geothermal various growth rates by type of application are assumed (i.e., hydrothermal electric/utility, hydrothermal electric/independent power producers (IPP), hot dry rock/IPP, magma electric/IPP, direct heat/residential, commercial and industrial, and direct heat/secondary oil recovery).

Wind is competitive with oil and gas at best wind sites.

Regional analysis considers environmental constraints in the Northeast, low wind resources in Federal Regions 3 and 4, slow penetration in Regions 5, 7 and 8 because of dominance of coal generation, moderate growth in Region 9 based on industry plans, and no penetration in Region 10 because of the availability of inexpensive hydropower.

Photovoltaics, based on gradually reduced costs, are assumed to contribute small amounts of energy beginning in the year 2005.

Utility Sector

For Solar Thermal the assumptions of reduced costs and utility acceptance lead to modest penetration beginning in 2005, reaching 1.4 GWe in 2010.

Wood and Waste assumes a growth rate of approximately 6 percent from the existing base of 0.02 Quadrillion Btu in 1988.

Hydropower assumes no retirements of existing plants. Future regional distribution is based on historical distribution. Low growth is assumed due to limitation on sites, both physical and environmental.

Geothermal assumptions are based on regional growth rates determined by on availability of resources, amounting to a national growth rate of 3.6 percent between 1988 and 2010.

Wind (see assumptions for wind under "End-Use Sectors") Utilities are assumed to purchase wind machines after 2000 when nonutilities have demonstrated their feasibility.

Photovoltaics assumptions are based on gradually reduced costs, moderate penetration beginning in 2000.

Electricity

The electric utility component of the PC-AEO model consists of three worksheet submodels: capacity ("UTILCAP")[18], generation ("UTILGEN"), and financial/pricing ("UTILFIN"). The purposes of UTILCAP and UTILGEN are to estimate energy use in the utility sector by fuel and by Census region and to calculate cost components of electricity generation for the financial and electricity pricing module, UTILFIN. The capacity planning component, UTILCAP, estimates the generating capacity additions required to meet projected electricity demand, beyond the level of additions already under construction or in planning by the utilities. UTILCAP adds the type of capacity, both in terms of peaking or nonpeaking and by plant type, by implementing the user's new-plant-type choices. The generation and fuel use component, UTILGEN determines the generation mix, energy use by plant type and fuel, fuel expense, and operations and maintenance cost. UTILFIN estimates electricity prices by determining the revenue requirements necessary to meet capital, fuel, and operations costs. Assumptions presented here are characteristic of the base case only. Appendix C presents the complete assumptions and methodologies for electricity and nuclear technologies.

Supply of electricity is assumed to be produced using existing capacity (some of which is life extended), planned capacity additions announced by utilities, purchases from nonutilities, imports, and demand-side management. When these sources are not sufficient to maintain reliability criteria, then utilities are assumed to build additional capacity subject to construction lead times given below.

New plant construction times are 8 years for coal, 5 years for combined cycle, and 3 years for combustion turbines. No new nuclear units become operable beyond units currently in the construction pipeline. No new hydroelectric plants, other than those announced by utilities, are assumed to become operational by 2010.

Nuclear Power

Nuclear units are assumed to have an operable life of 40 years without life extension.

Nuclear operable capability increases from 95 gigawatts (GWe) at the end of 1988 to 104 GWe in 2000 and then declines to 100 GWe by 2010.

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[18] Energy Information Administration, *PC-AEO Forecasting Model for the Annual Energy Outlook 1990*, DOE/EIA-M036 (Washington, DC, March 1990).

In 1988, the average annual capacity factor for nuclear units was 63.5 percent, the highest level since 1978. The assumed average capacity factor for 2010 is 68 percent, which is only a modest increase over the next 20 years. The are four reasons we assume a moderate increase will occur:

1. Historically, units beginning operation have operated at a lower capacity factor than mature units. This characteristic lowers the average for any year in which many new units begin operation. Two factors will negate this effect in the future: starting in 1988, the capacity factor for units starting-up has been improving, and only a few new units are scheduled to begin operating in the forecast period.
2. Many productivity improvement programs have been put into effect and Public Utility Commissions have established performance incentive programs. Also, extending the fuel cycle to 18 months from 12 months results in less downtime for refueling.
3. In comparison to foreign nuclear capacity factors, the assumed factors for the United States are reasonable.
4. A statistical analysis of capacity factors for nuclear plants has not found any significant deterioration with age to date.[19]

Fossil-Fuel Steam Plants

With respect to fossil-fuel steam plants, historical data indicate that plant performance degrades over time without refurbishment, especially after 30 years of operation. However, it is assumed that utilities will refurbish most of their fossil-fuel steam plants between their 25th and 30th years to prevent a decline in performance. About one quarter of the fossil-fuel steam plants are expected to be partially refurbished and as a result their maximum achievable capacity factor is restricted to 40 percent after their 25th year of operation. In addition, while the current average annual capacity factor for fossil-fuel steam plants is well below 68 percent (the limit given in the assumption) many individual units are operating well above this level, with some operating at capacity factors between 80 and 85 percent. It appears that lack of demand is the factor for low average capacity factors of many existing units. As demand grows, output from many of these plants will be increased substantially. Also, while few new fossil-fuel steam plants have been announced by utilities, the base case projects the need for numerous new fossil-fuel steam plants (primarily coal-fired) beginning in the late 1990's. These new plants have higher capacity factors contributing to an average 68 percent capacity factor.

Capital Costs

Overnight capital costs for new plants are $302 per kilowatt (kW) for a combustion turbine (1988 dollars), $521 per kW for a combined cycle plant, and $1,266 to $1,448 per kW for a coal plant depending on the rank and sulfur content of the coal. These figures are national averages, regional costs vary slightly from them.

Life-cycle costing analysis is used to determine the type of new generating equipment. Fuel price expectations through 2048 are used for this decision.

The cost of capital is specified as follows. Historical values for allowed return on equity, the cost of preferred stock, and the cost of long-term debt are used, along with the forecast of the AA utility bond rating, to predict the future costs of debt and common and preferred equity. The cost of long-term debt, for example, is a function of the previous year's cost of debt and the previous year's AA utility bond rate. The cost of capital for electric utilities is based on the Data Resources, Inc. (DRI) forecasted AA utility bond rate as modified by EIA to represent the macro-economic assumptions in the base case. The allowed return on common equity, preferred equity and long term debt are calculated as a function of the corporate AA utility bond rate. The relationship was econometrically estimated at the federal and census region using historical data. The marginal cost of debt and preferred equity are combined with the current outstanding debt to calculate embedded cost of debt. Because DRI forecasts all macroeconomic indicators simultaneously, their forecast of the corporate AA utility bond rate is consistent with the Federal Funds rate. Between 1984 and 1988 the cost of capital for investor-owned electric utilities ranged from 10.5 to 12.5 percent (nominal) based on EIA and Utility Compustat Data. This range is consistent with a 6.1 percent real return.

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[19] System Sciences, Inc., *Analysis of Capacity Factors* (Bethesda, MD, September 1986).

Operations and Maintenance

Planned generating plant retirements announced by utilities are 14.5 GWe. Additional retirements of 36.7 GWe are assumed to occur by 2010.

Life extension is assumed to be performed on 346 GWe of capacity by 2010 at a cost of $59 to $216 per kW. Some of the capacity (62 GWe) is partially life extended and the rest (284 GWe) is fully life extended. The partially extended plants are limited to a capacity factor of 40 percent.

The life extension assumptions are based on interpreting laws and regulations already in place. No new laws and regulations (or court decisions) are required for the agreed upon assumptions to occur. During the discussion of the life extension assumptions the impact of the Wisconsin Electric Power Company (WEPCO) case on utility life extension plans was vigorously debated. It was agreed that most older fossil-fuel steam plants (about 90 percent of existing fossil-fuel steam capacity) would be refurbished if it were economical. However, some felt that the WEPCO case indicated that EPA intended to require older plants to comply with New Source Performance Standards (NSPS) environmental standards if they were refurbished. If this were true, utilities would still be expected to refurbish most of their older fossil-fuel steam capacity, but a larger portion of them (approximately half) would only be partially life-extended. These partially life-extended plants would not have to comply with NSPS environmental standards and would be able to continue operating, but at a reduced level of performance. The majority of the life-extension subcommittee did not agree with this view, but instead felt that the WEPCO case should be viewed as a single incident without broad implications for the industry. As a result, in the base case, approximately three-quarters of the life extended capacity is assumed to be fully refurbished while the remainder are only partially life extended. Due to uncertainty about how EPA will interpret/apply existing legislation (especially in light of the recent WEPCO decision) a sensitivity case which assumes less life extension could be considered.

Environmental standards represented include: State implementation plans, new source performance standards, revised new source performance standards, and prevention of significant deterioration.

The maximum achievable capacity factor for fossil-fueled plants is assumed to be the greater of either the level achieved historically or 68 percent.

Efficiencies for new generating plants range from 31 to 41 percent depending on the plant type.

Operations and maintenance costs have both fixed and variable components. For a coal plant, the fixed cost varies from $12 to $27 (1988 dollars) per kW per year and the variable component ranges from 1.0 to 6.1 mills per kilowatthour (kWh). Coal costs are based on a model that analyzes historic costs collected on the FERC Form 1 (a financial disclosure form filed annually by major private electric utilities, licensees, and others). Costs for other plant types are estimates prepared by the Electric Power Research Institute. Nuclear O&M costs are assumed to escalate in real terms by 1.5 percent per year. In addition, nuclear units are assumed to have capitalized maintenance costs (capital additions) of $40 per kWe per year (1988 dollars) in the first year of the forecast period, that decrease by $2 per kWe per year for the first five years, and then increase by 2.7 percent per year thereafter.

Nuclear fuel costs are assumed to decline in real terms from 7.0 mills per kWe (1988 dollars) in 1989 to 4.9 mills in 2010.

Transmission and distribution (T&D) losses are 7 to 8.5 percent across the Federal regions. These are reasonable approximations prepared by utilities of actual and forecast losses. Very little is known about T&D loss rates, because the costs of measuring them are too high; furthermore, we are not aware of any T&D technological improvements which could materially reduce T&D losses pre-2010. The primary issues associated with T&D are legal and regulatory and not addressable by EIA base case assumptions.

Load characteristics are based on aggregations of hourly data from 1973 to 1982 and do not change in the future.

Imports of electricity are assumed to increase from 32 billion kWh in 1988 and reach 60 billion kWh in 2000 and 68 billion kWh in 2010.

Demand side management will provide 57 billion kWh of additional generation in 2000 and 171 billion kWh in 2010.

Advanced technologies for both combined-cycle and coal plants are available in 2005. The characteristics of these plants are generic and represent a composite of several new technologies.

Nonutility Generation

Total electricity generation from nonutilities is forecast to grow from 178 billion kWh in 1988 to 544 kWh in 2010. Although less than one-half of nonutility generation was sold to electric utilities in 1988, by 2010 over 60 percent is expected to be generated for the grid. Nonutility generation includes generation from fossil fuels, primarily natural gas, and from nonfossil sources such as biomass and waste, geothermal, hydroelectric, solar, and wind. By the year 2000, nonfossil fuels will provide about 30 percent of nonutility capacity, with fossil sources providing the rest.

Appendix A

Residential Sector Technology Description Tables
and
Commercial Sector Input Data

Residential Sector Technology Description Tables

Table A1. Refrigeration (Electric): All Regions

Technology	R1	R2	R3	R4	R5
Level (LBL)	Base	L3	L7	L10	L12
Capital Cost (88$)	534.00	544.00	591.00	665.00	705.00
Capital Cost (82$)	438.78	447.00	485.62	546.43	579.29
Energy In (Kwh/Yr)	947	787	662	595	515
Energy In (MMBtu/Yr)	3.23	2.69	2.26	2.03	1.76
Energy Out (MMBtu/Yr)	1.76	1.76	1.76	1.76	1.76
O&M Cost (82$)	0	0	0	0	0
Efficiency	0.54	0.65	0.78	0.87	1.00
Life (Years)	19	19	19	19	19
XTMS	1	-	-	-	-
NTMS	-	0.1	0.1	0.1	0.1

Note: Columns R1-R6 are for increasing levels of refrigeration efficiency
XTMS = Existing Technology Market Share
NTMS = New Technology Market Share
Refrigerator Type: Top-Mount Auto Defrost Refrigerator-Freezer
Efficiency: Efficiency Index (Based on an Eff=1 for a Level 12 Refrigerator-Freezer)
Source: Cohen, S., LBL, "Energy Efficiency Technologies for Residential and Commercial Buildings," 4/17/89, p. 30.

Table A2. Hot Water Heaters: All Regions

Technology	Electric		Gas	
	E1	E2	G1	G2
Capital Cost (87$)	164.00	196.00	203.00	227.00
Capital Cost (82$)	139.34	166.53	172.47	192.86
Electrical Use (Kwh/Yr)	3900	3229	-	-
Gas Use (Therm/Yr)	-	-	250	185
Energy In (MMBtu/Yr)	13.3	11.0	25.0	18.5
Energy Out (MMBtu/Yr)	10.2	10.2	16.5	16.5
O&M Cost (82$)	0	0	0	0
Efficiency	0.77	0.93	0.66	0.89
Life (Years)	13	13	13	13
XTMS	1	1	-	-
NTMS	-	0.1	-	0.1

Note: Columns E1-E2 and G1-G2 are for increased levels of heating efficiency
XTMS = Existing Technology Market Share
NTMS = New Technology Market Share
Efficiency: Efficiency Index (Based on Energy Guide Labels)
Source: DOE, "Technical Support Document: In Support of Interim Energy Conservation Standards . DOE/CE-0223, Vol. 2, June 1988, pp. 3.51, 3.52.

Table A3. Cooling: Northeast Region

	Electric Air Conditioning			Electric Heat Pumps		
Technology	**EAC1**	**EAC2**	**EAC3**	**EHP1**	**EHP2**	**EHP3**
Capital Cost (88$)	1300.00	1380.00	1420.00	-	-	-
Capital Cost (87$)	-	-	-	1800.00	2800.00	3600.00
Capital Cost (82$)	1068.20	1133.94	1166.80	1529.31	2378.93	3058.62
Capacity (Btu/Hr)	36000	36000	36000	36000	36000	36000
Cooling Time (Hrs/Yr)	500	500	500	500	500	500
O&M Cost	42.48	42.48	42.48	42.48	42.48	42.48
Efficiency (SEER)	7.0	7.5	9.1	10.0	11.0	12.0
Efficiency	2.05	2.20	2.67	2.93	3.22	3.52
Life (Years)	14	14	14	14	14	14
Utilization (Heat Pump)	1	1	1	0.17	0.17	0.17
XTMS	1	-	-	1	-	-
NTMS	-	0.1	0.1	-	0.1	0.1

Note: Columns EAC1-EAC3 and EHP1-EHP3 are for increasing levels of cooling efficiency.
XTMS = Existing Technology Market Share
NTMS = New Technology Market Share
Electric Air Conditioning Type: Nominal 35KBtu/hr Central Air Conditioner
Sources: Cohen, S., LBL, "Energy Efficiency Technologies for Residential and Commercial Buildings," 4-17-89, p. 26; DOE, "Technical Support Document: In Support of Interim Energy Conservation Standards...," DOE/CE-0223 Vol. 2, June 1988, p. 3.50. Electric Heat Pump: PNL, "Technical Support Document: Automated Residential Energy Standard," PNL-6979, Vol. 2, May 1989. Cooling Hours: Air Conditioning and Refrigeration Institute, "ARI Unitary Directory," August 1989.

Table A4. Cooling: Midwest Region

	Electric Air Conditioning			Electric Heat Pumps		
Technology	**EAC1**	**EAC2**	**EAC3**	**EHP1**	**EHP2**	**EHP3**
Capital Cost (88$)	1300.00	1380.00	1420.00	-	-	-
Capital Cost (87$)	-	-	-	1800.00	2800.00	3600.00
Capital Cost (82$)	1068.20	1133.94	1166.80	1529.31	2378.93	3058.62
Capacity (Btu/Hr)	36000	36000	36000	36000	36000	36000
Cooling Time (Hrs/Yr)	700	700	700	700	700	700
O&M Cost	42.48	42.48	42.48	42.48	42.48	42.48
Efficiency (SEER)	7.0	7.5	9.1	10.0	11.0	12.0
Efficiency	2.05	2.20	2.67	2.93	3.22	3.52
Life (Years)	14	14	14	14	14	14
Utilization (Heat Pump)	1	1	1	0.23	0.23	0.23
XTMS	1	-	-	1	-	-
NTMS	-	0.1	0.1	-	0.1	0.1

Note: Columns EAC1-EAC3 and EHP1-EHP3 are for increasing levels of cooling efficiency
XTMS = Existing Technology Market Share
NTMS = New Technology Market Share
Electric Air Conditioning Type: Nominal 35KBtu/hr Central Air Conditioner
Sources: Cohen, S., LBL, "Energy Efficiency Technologies for Residential and Commercial Buildings," 4-17-89, p. 26; DOE, "Technical Support Document: In Support of Interim Energy Conservation Standards...," DOE/CE-0223 Vol. 2, June 1988, p. 3.50. Electric Heat Pump: PNL, "Technical Support Document: Automated Residential Energy Standard," PNL-6979, Vol. 2, May 1989. Cooling Hours: Air Conditioning and Refrigeration Institute, "ARI Unitary Directory," August 1989.

Table A5. Cooling: South Region

Technology	Electric Air Conditioning			Electric Heat Pumps		
	EAC1	EAC2	EAC3	EHP1	EHP2	EHP3
Capital Cost (88$)	1300.00	1380.00	1420.00	-	-	-
Capital Cost (87$)	-	-	-	1800.00	2800.00	3600.00
Capital Cost (82$)	1068.20	1133.94	1166.80	1529.31	2378.93	3058.62
Capacity (Btu/Hr)	36000	36000	36000	36000	36000	36000
Cooling Time (Hrs/Yr)	1300	1300	1300	1300	1300	1300
O&M Cost	42.48	42.48	42.48	42.48	42.48	42.48
Efficiency (SEER)	7.0	7.5	9.1	10.0	11.0	12.0
Efficiency	2.05	2.20	2.67	2.93	3.22	3.52
Life (Years)	14	14	14	14	14	14
Utilization (Heat Pump)	1	1	1	0.29	0.29	0.29
XTMS	1	-	-	1	-	-
NTMS	-	0.1	0.1	-	0.1	0.1

Note: Columns EAC1-EAC3 and EHP1-EHP3 are for increasing levels of cooling efficiency
XTMS = Existing Technology Market Share
NTMS = New Technology Market Share
Electric Air Conditioning Type: Nominal 35KBtu/hr Central Air Conditioner
Sources: Cohen, S., LBL, "Energy Efficiency Technologies for Residential and Commercial Buildings," 4-17-89, p. 26; DOE, "Technical Support Document: In Support of Interim Energy Conservation Standards...," DOE/CE-0223 Vol. 2, June 1988, p. 3.50. Electric Heat Pump: PNL, "Technical Support Document: Automated Residential Energy Standard," PNL-6979, Vol. 2, May 1989. Cooling Hours: Air Conditioning and Refrigeration Institute, "ARI Unitary Directory," August 1989.

Table A6. Cooling: West Region

Technology	Electric Air Conditioning			Electric Heat Pumps		
	EAC1	EAC2	EAC3	EHP1	EHP2	EHP3
Capital Cost (88$)	1300.00	1380.00	1420.00	-	-	-
Capital Cost (87$)	-	-	-	1800.00	2800.00	3600.00
Capital Cost (82$)	1068.20	1133.94	1166.80	1529.31	2378.93	3058.62
Capacity (Btu/Hr)	36000	36000	36000	36000	36000	36000
Cooling Time (Hrs/Yr)	1000	1000	1000	1000	1000	1000
O&M Cost	42.48	42.48	42.48	42.48	42.48	42.48
Efficiency (SEER)	7.0	7.5	9.1	10.0	11.0	12.0
Efficiency	2.05	2.20	2.67	2.93	3.22	3.52
Life (Years)	14	14	14	14	14	14
Utilization (Heat Pump)	1	1	1	0.33	0.33	0.33
XTMS	1	-	-	1	-	-
NTMS	-	0.1	0.1	-	0.1	0.1

Note: Columns EAC1-EAC3 and EHP1-EHP3 are for increasing levels of cooling efficiency
XTMS = Existing Technology Market Share
NTMS = New Technology Market Share
Electric Air Conditioning Type: Nominal 35KBtu/hr Central Air Conditioner
Sources: Cohen, S., LBL, "Energy Efficiency Technologies for Residential and Commercial Buildings," 4-17-89, p. 26; DOE, "Technical Support Document: In Support of Interim Energy Conservation Standards...," DOE/CE-0223 Vol. 2, June 1988, p. 3.50. Electric Heat Pump: PNL, "Technical Support Document: Automated Residential Energy Standard," PNL-6979, Vol. 2, May 1989. Cooling Hours: Air Conditioning and Refrigeration Institute, "ARI Unitary Directory," August 1989.

Table A7. Heating: Northeast Region

Technology	Electric Heat Pumps			Oil Furnaces		Gas Furnaces			Electric Baseboards
	EHP1	EHP2	EHP3	OFU1	OFU3	GFU1	GFU2	GFU3	HELB
Capital Cost (87$)	1800.00	2800.00	3600.00	550.00	700.00	-	-	-	634.90
Capital Cost (88$)	-	-	-	-	-	411.00	622.00	631.00	-
Capital Cost (82$)	1529.31	2378.93	3058.62	467.29	594.73	337.72	511.09	518.49	539.42
Heat Req. (MMBtu/Yr)	130	130	130	130	130	130	130	130	130
Heating Hours/Yr	2500	2500	2500	2500	2500	2500	2500	2500	2500
O&M Cost	42.48	42.48	42.48	42.48	42.48	42.48	42.48	42.48	42.48
Efficiency (HSPF)	7.3	8.5	9.8	-	-	-	-	-	-
Efficiency	2.14	2.49	2.87	0.70	0.90	0.62	0.81	0.92	0.95
Life (Years)	23	23	23	23	23	23	23	23	23
Utilization (Heat Pump)	0.83	0.83	0.83	1	1	1	1	1	1
XTMS	1	-	-	0.36	-	0.54	-	-	0.10
NTMS	-	0.1	0.1	-	0.04	-	0.05	0.05	-

Note: Columns EHP1-EHP3, OFU1-OFU3 and GFU1-GFU3 are for increasing levels of heating efficiency
XTMS = Existing Technology Market Share
NTMS = New Technology Market Share

Sources: **Electric Heat Pumps.** PNL, "Technical Support Document: Automated Residential Energy Standard," PNL-6979, Vol. 2, May 1989. **Electric Baseboard Heat (HELB).** PNL, "Technical Support Document: Automated Residential Energy Standard," PNL-6979, Vol. 2, May 1989. **Oil Furnaces.** Annual Fuel Utilization Efficiency (AFUE); DOE, "Technical Support Document: In Support of Interim Energy Conservation Standards...," DOE/CE-0223, Vol. 2, June 1988, p. 3.47. **Gas Furnaces.** Type: 80KBtu Central Warm Air Furnace; Annual Fuel Utilization Efficiency (AFUE); Cohen, S., LBL, "Energy Efficiency Technologies for Residential and Commercial Buildings," 4/17/89, p. 9.; DOE, "Technical Support Document: In Support of Interim Energy Conservation Standards...," DOE/CE-0223, Vol. 2, June 1988, p. 3.46. **Heating Hours.** Air Conditioning and Refrigeration Institute, "ARI Unitary Directory," August 1989.

Table A8. Heating: Midwest Region

Technology	Electric Heat Pumps			Oil Furnaces		Gas Furnaces			Electric Baseboards
	EHP1	EHP2	EHP3	OFU1	OFU3	GFU1	GFU2	GFU3	HELB
Capital Cost (87$)	1800.00	2800.00	3600.00	550.00	700.00	-	-	-	634.90
Capital Cost (88$)	-	-	-	-	-	411.00	622.00	631.00	-
Capital Cost (82$)	1529.31	2378.93	3058.62	467.29	594.73	337.72	511.09	518.49	539.42
Heat Req. (MMBtu/Yr)	114	114	114	114	114	114	114	114	114
Heating Hours/Yr	2350	2350	2350	2350	2350	2350	2350	2350	2350
O&M Cost	42.48	42.48	42.48	42.48	42.48	42.48	42.48	42.48	42.48
Efficiency (HSPF)	7.3	8.5	9.8	-	-	-	-	-	-
Efficiency	2.14	2.49	2.87	0.70	0.90	0.62	0.81	0.92	0.95
Life (Years)	23	23	23	23	23	23	23	23	23
Utilization (Heat Pump)	0.77	0.77	0.77	1	1	1	1	1	1
XTMS	1	-	-	0.01	-	0.97	-	-	0.02
NTMS	-	0.1	0.1	-	0.00	-	0.01	0.01	-

Note: Columns EHP1-EHP3, OFU1-OFU3 and GFU1-GFU3 are for increasing levels of heating efficiency
XTMS = Existing Technology Market Share
NTMS = New Technology Market Share

Sources: **Electric Heat Pumps.** PNL, "Technical Support Document: Automated Residential Energy Standard," PNL-6979, Vol. 2, May 1989. **Electric Baseboard Heat (HELB).** PNL, "Technical Support Document: Automated Residential Energy Standard," PNL-6979, Vol. 2, May 1989. **Oil Furnaces.** Annual Fuel Utilization Efficiency (AFUE); DOE, "Technical Support Document: In Support of Interim Energy Conservation Standards...," DOE/CE-0223, Vol. 2, June 1988, p. 3.47. **Gas Furnaces.** Type: 80KBtu Central Warm Air Furnace; Annual Fuel Utilization Efficiency (AFUE); Cohen, S., LBL, "Energy Efficiency Technologies for Residential and Commercial Buildings," 4/17/89, p. 9.; DOE, "Technical Support Document: In Support of Interim Energy Conservation Standards...," DOE/CE-0223, Vol. 2, June 1988, p. 3.46. **Heating Hours.** Air Conditioning and Refrigeration Institute, "ARI Unitary Directory," August 1989.

Table A9. Heating: South Region

	Electric Heat Pumps			Oil Furnaces		Gas Furnaces			Electric Baseboards
Technology	EHP1	EHP2	EHP3	OFU1	OFU3	GFU1	GFU2	GFU3	HELB
Capital Cost (87$)	1800.00	2800.00	3600.00	550.00	700.00	-	-	-	634.90
Capital Cost (88$)	-	-	-	-	-	411.00	622.00	631.00	-
Capital Cost (82$)	1529.31	2378.93	3058.62	467.29	594.73	337.72	511.09	518.49	539.42
Heat Req. (MMBtu/Yr)	94	94	94	94	94	94	94	94	94
Heating Hours/Yr	2200	2200	2200	2200	2200	2200	2200	2200	2200
O&M Cost	42.48	42.48	42.48	42.48	42.48	42.48	42.48	42.48	42.48
Efficiency (HSPF)	7.3	8.5	9.8	-	-	-	-	-	-
Efficiency	2.14	2.49	2.87	0.70	0.90	0.62	0.81	0.92	0.95
Life (Years)	23	23	23	23	23	23	23	23	23
Utilization (Heat Pump)	0.63	0.63	0.63	1	1	1	1	1	1
XTMS	1	-	-	0.03	-	0.90	-	-	0.08
NTMS	-	0.1	0.1	-	0.00	-	0.09	0.09	-

Note: Columns EHP1-EHP3, OFU1-OFU3 and GFU1-GFU3 are for increasing levels of heating efficiency
XTMS = Existing Technology Market Share
NTMS = New Technology Market Share
Sources: **Electric Heat Pumps.** PNL, "Technical Support Document: Automated Residential Energy Standard," PNL-6979, Vol. 2, May 1989. **Electric Baseboard Heat (HELB).** PNL, "Technical Support Document: Automated Residential Energy Standard," PNL-6979, Vol. 2, May 1989. **Oil Furnaces.** Annual Fuel Utilization Efficiency (AFUE); DOE, "Technical Support Document: In Support of Interim Energy Conservation Standards...," DOE/CE-0223, Vol. 2, June 1988, p. 3.47. **Gas Furnaces.** Type: 80KBtu Central Warm Air Furnace; Annual Fuel Utilization Efficiency (AFUE); Cohen, S., LBL, "Energy Efficiency Technologies for Residential and Commercial Buildings," 4/17/89, p. 9.; DOE, "Technical Support Document: In Support of Interim Energy Conservation Standards..," DOE/CE-0223, Vol. 2, June 1988, p. 3.46. **Heating Hours.** Air Conditioning and Refrigeration Institute, "ARI Unitary Directory," August 1989.

Table A10. Heating: West Region

	Electric Heat Pumps			Oil Furnaces		Gas Furnaces			Electric Baseboards
Technology	EHP1	EHP2	EHP3	OFU1	OFU3	GFU1	GFU2	GFU3	HELB
Capital Cost (87$)	1800.00	2800.00	3600.00	550.00	700.00	-	-	-	634.90
Capital Cost (88$)	-	-	-	-	-	411.00	622.00	631.00	-
Capital Cost (82$)	1529.31	2378.93	3058.62	467.29	594.73	337.72	511.09	518.49	539.42
Heat Req. (MMBtu/Yr)	88	88	88	88	88	88	88	88	88
Heating Hours/Yr	2000	2000	2000	2000	2000	2000	2000	2000	2000
O&M Cost	42.48	42.48	42.48	42.48	42.48	42.48	42.48	42.48	42.48
Efficiency (HSPF)	7.3	8.5	9.8	-	-	-	-	-	-
Efficiency	2.14	2.49	2.87	0.70	0.90	0.62	0.81	0.92	0.95
Life (Years)	23	23	23	23	23	23	23	23	23
Utilization (Heat Pump)	0.67	0.67	0.67	1	1	1	1	1	1
XTMS	1	-	-	0.01	-	0.93	-	-	0.05
NTMS	-	0.1	0.1	-	0.00	-	0.09	0.09	-

Note: Columns EHP1-EHP3, OFU1-OFU3 and GFU1-GFU3 are for increasing levels of heating efficiency
XTMS = Existing Technology Market Share
NTMS = New Technology Market Share
Sources: **Electric Heat Pumps.** PNL, "Technical Support Document: Automated Residential Energy Standard," PNL-6979, Vol. 2, May 1989. **Electric Baseboard Heat (HELB).** PNL, "Technical Support Document: Automated Residential Energy Standard," PNL-6979, Vol. 2, May 1989. **Oil Furnaces.** Annual Fuel Utilization Efficiency (AFUE); DOE, "Technical Support Document: In Support of Interim Energy Conservation Standards...," DOE/CE-0223, Vol. 2, June 1988, p. 3.47. **Gas Furnaces.** Type: 80KBtu Central Warm Air Furnace; Annual Fuel Utilization Efficiency (AFUE); Cohen, S., LBL, "Energy Efficiency Technologies for Residential and Commercial Buildings," 4/17/89, p. 9.; DOE, "Technical Support Document: In Support of Interim Energy Conservation Standards..," DOE/CE-0223, Vol. 2, June 1988, p. 3.46. **Heating Hours.** Air Conditioning and Refrigeration Institute, "ARI Unitary Directory," August 1989.

Commercial Sector Input Data

Table A11. Civilian Employment
(Million Persons)

	1986	1988	1990	1995	2000	2010	Percent Growth 1988-2010
Mid Macro Case							
Northeast	24.67	25.60	26.03	27.54	28.94	31.07	0.9
Midwest	27.81	29.08	29.94	31.58	33.10	33.87	0.7
South	35.36	37.22	38.67	41.81	44.58	49.03	1.3
West	21.76	23.07	24.08	26.57	28.75	31.50	1.4
United States	109.60	114.97	118.71	127.50	135.36	145.47	1.1
Low Macro Case							
Northeast	24.67	25.60	25.64	26.84	27.92	29.58	0.7
Midwest	27.81	29.08	29.49	30.78	31.93	32.24	0.5
South	35.36	37.22	38.08	40.75	43.00	46.67	1.0
West	21.76	23.07	23.71	25.90	27.73	29.99	1.2
United States	109.60	114.97	116.93	124.27	130.57	138.47	0.8
High Macro Case							
Northeast	24.67	25.60	26.43	28.24	29.96	32.56	1.1
Midwest	27.81	29.08	30.40	32.38	34.27	35.49	0.9
South	35.36	37.22	39.26	42.86	46.15	51.37	1.5
West	21.76	23.07	24.45	27.25	29.76	33.01	1.6
United States	109.60	114.97	120.54	130.73	140.15	152.44	1.3

Source: Based on the DRI July Trend 25 year 0789 Control Simulation of the Commercial model adjusted for EIA prices and macroeconomic assumptions.

Table A12. Floorspace in New Buildings
(Million Square Feet)

	Warehouse	Retail/ Wholesale	Food Sales/ Service	Office	Education	Continuous Use	Miscellaneous	Total
Northeast	40.37	83.82	1.42	36.41	3.21	14.03	25.99	205.3
Midwest	64.79	101.80	8.14	80.88	16.89	19.65	88.19	380.3
South	60.20	136.40	20.02	119.60	36.07	71.58	71.69	515.6
West	26.51	38.12	20.47	121.80	20.28	38.10	45.41	310.7

Note: Estimated from the 1986 NBECS as defined in the attached memorandum in Appendix F, *Inputs to Commercial Models Calibrated to 1986 NBECS*, Miriam Goldberg. The floorspace is calculated by dividing the 1980-1986 NBECS estimates by 7.

Table A13. New Building Energy Use Intensity
(Thousand Btu/Square Feet)

	Warehouse	Retail/ Wholesale	Food Sales/ Service	Office	Education	Continuous Use	Miscel- laneous
Northeast							
Heating	22.35	15.32	184.40	45.94	70.65	80.59	64.68
Cooling	2.13	5.24	18.72	14.61	10.11	13.21	3.55
Water Heating	0.25	0.69	25.69	1.48	5.61	10.69	1.28
Cooking	0.00	0.25	16.43	0.00	0.00	18.68	0.05
Lighting	17.90	11.78	41.46	18.94	13.11	24.32	17.94
Other	6.25	6.57	46.48	6.43	23.19	17.78	4.63
Total Buildings	**48.88**	**39.85**	**333.23**	**87.39**	**122.67**	**165.28**	**92.13**
Midwest							
Heating	29.50	37.97	49.92	39.94	29.54	51.96	32.31
Cooling	2.91	15.33	5.59	14.35	3.53	7.49	3.24
Water Heating	0.15	0.66	8.47	0.96	1.34	8.64	0.51
Cooking	0.00	0.36	3.30	0.00	0.00	8.34	0.41
Lighting	13.57	23.54	23.76	17.31	5.67	10.65	14.88
Other	5.03	8.07	31.06	5.74	4.44	10.00	11.92
Total Buildings	**51.17**	**85.93**	**122.10**	**78.28**	**44.52**	**97.08**	**63.27**
South							
Heating	12.66	21.11	61.96	21.60	17.23	17.38	7.09
Cooling	6.58	20.93	35.96	33.05	9.89	16.97	9.83
Water Heating	0.23	0.57	21.68	1.08	2.23	5.32	0.32
Cooking	0.00	0.41	13.65	0.00	0.00	7.43	0.13
Lighting	9.20	13.57	33.60	13.31	7.77	7.67	14.54
Other	4.58	10.07	35.82	4.74	8.65	5.19	5.83
Total Buildings	**33.25**	**66.66**	**202.68**	**73.79**	**45.78**	**59.97**	**37.73**
West							
Heating	8.60	27.94	97.85	24.09	28.46	28.18	16.08
Cooling	1.48	19.04	21.45	15.31	5.05	19.08	3.46
Water Heating	0.17	0.78	34.64	0.91	2.56	14.07	0.40
Cooking	0.00	0.88	21.70	0.00	0.00	16.44	0.12
Lighting	7.84	45.47	43.63	18.94	11.99	16.59	13.99
Other	3.71	13.16	66.55	6.29	10.98	16.47	12.04
Total Buildings	**21.80**	**107.26**	**285.82**	**65.53**	**59.03**	**110.84**	**46.08**

Source: Estimated from the 1986 NBECS as defined in the attached memorandum in Appendix F, *Inputs to Commercial Models Calibrated to 1986 NBECS*, Miriam Goldberg.

Table A14. Existing Building Energy Use Intensity
(Thousand Btu/Square Feet)

	Warehouse	Retail/ Wholesale	Food Sales/ Service	Office	Education	Continuous Use	Miscel- laneous
Northeast							
Heating	56.26	120.53	34.56	70.51	86.32	53.41	72.73
Cooling	5.14	18.06	2.26	35.67	9.69	10.99	7.90
Water Heating	0.33	2.23	5.47	2.18	6.69	8.31	1.48
Cooking	0.09	0.45	2.34	0.00	0.00	11.39	0.68
Lighting	23.39	46.20	9.36	46.41	17.75	17.10	38.24
Other	8.16	28.66	10.40	15.94	20.67	12.83	22.16
Total Buildings . .	**93.37**	**216.13**	**64.40**	**170.70**	**141.12**	**114.03**	**143.20**
Midwest							
Heating	82.54	159.41	59.47	147.46	109.06	80.34	100.35
Cooling	5.71	39.33	9.68	53.69	10.02	31.71	15.98
Water Heating	0.36	1.91	11.11	2.84	5.45	13.12	1.36
Cooking	0.07	1.02	7.57	0.00	0.00	20.45	0.59
Lighting	26.62	61.00	21.11	53.46	26.32	25.02	41.94
Other	9.87	29.28	28.38	19.82	20.10	21.82	33.44
Total Buildings . .	**125.17**	**291.94**	**137.32**	**277.27**	**170.95**	**192.46**	**193.66**
South							
Heating	61.92	108.34	29.86	78.82	59.52	49.56	43.88
Cooling	32.29	112.38	19.57	105.67	27.80	60.99	44.82
Water Heating	1.00	3.27	12.06	3.57	7.34	13.62	1.50
Cooking	0.00	1.45	7.02	0.01	0.00	18.66	1.19
Lighting	54.26	69.18	15.79	40.95	19.07	25.61	54.72
Other	27.00	50.07	17.84	19.97	21.98	18.57	37.65
Total Buildings . .	**176.47**	**344.69**	**102.14**	**248.98**	**135.71**	**187.01**	**183.75**
West							
Heating	16.57	42.44	26.71	87.90	40.75	41.29	39.79
Cooling	4.41	17.30	5.81	54.44	6.35	14.26	10.85
Water Heating	0.29	1.30	10.23	3.22	4.53	19.00	1.25
Cooking	0.02	0.51	5.66	0.00	0.00	16.21	0.98
Lighting	17.87	39.92	13.02	70.57	17.59	15.39	51.42
Other	8.70	19.06	19.66	24.67	18.79	20.99	34.74
Total Buildings . .	**47.85**	**120.53**	**81.08**	**240.81**	**88.00**	**127.14**	**139.03**

Source: Estimated from the 1986 NBECS as defined in the attached memorandum in Appendix F, *Inputs to Commercial Models Calibrated to 1986 NBECS*, Miriam Goldberg.

Table A15. New Equipment Consumption Fuel Shares

	Heating	Cooling	Water Heating	Cooking	Lighting	Other Uses	Total
Northeast							
Electricity	0.265	0.943	0.386	0.119	1.000	0.730	0.556
Gas	0.380	0.047	0.478	0.881	0.000	0.270	0.259
Oil	0.355	0.010	0.136	0.000	0.000	0.000	0.185
Midwest							
Electricity	0.311	0.969	0.427	0.169	1.000	0.531	0.581
Gas	0.672	0.031	0.537	0.831	0.000	0.466	0.410
Oil	0.017	0.000	0.036	0.000	0.000	0.003	0.009
South							
Electricity	0.583	0.923	0.617	0.430	1.000	0.621	0.775
Gas	0.375	0.078	0.371	0.571	0.000	0.379	0.213
Oil	0.042	0.000	0.012	0.000	0.000	0.000	0.013
West							
Electricity	0.516	0.918	0.112	0.084	1.000	0.712	0.692
Gas	0.476	0.082	0.848	0.916	0.000	0.288	0.303
Oil	0.008	0.040	0.000	0.000	0.000	0.000	0.005

Source: Estimated from the 1986 NBECS as defined in the attached memorandum in Appendix F, *Inputs to Commercial Models Calibrated to 1986 NBECS*, Miriam Goldberg.

Table A16. Existing Equipment Consumption Fuel Shares

	Heating	Cooling	Water Heating	Cooking	Lighting	Other Uses	Total
Northeast							
Electricity	0.168	0.745	0.243	0.223	1.000	0.600	0.456
Gas	0.327	0.126	0.445	0.775	0.000	0.401	0.259
Oil	0.505	0.129	0.313	0.003	0.000	0.000	0.286
Midwest							
Electricity	0.159	0.684	0.187	0.191	1.000	0.523	0.420
Gas	0.772	0.255	0.760	0.810	0.000	0.477	0.534
Oil	0.069	0.061	0.053	0.000	0.000	0.000	0.046
South							
Electricity	0.298	0.829	0.333	0.230	1.000	0.537	0.629
Gas	0.511	0.169	0.612	0.769	0.000	0.463	0.309
Oil	0.192	0.003	0.055	0.000	0.000	0.000	0.062
West							
Electricity	0.328	0.866	0.131	0.056	1.000	0.564	0.604
Gas	0.606	0.134	0.789	0.945	0.000	0.434	0.369
Oil	0.066	0.080	0.000	0.000	0.000	0.002	0.027

Source: Estimated from the 1986 NBECS as defined in the attached memorandum in Appendix F, *Inputs to Commercial Models Calibrated to 1986 NBECS*, Miriam Goldberg.

Table A17. Price and Employment Elasticities by Fuel and Service Type

Price Elasticities	Heating	Cooling	Water Heating	Cooking	Lighting	Other Uses
Northeast						
Electricity	-0.15	-0.16	-0.04	-0.09	-0.10	0.00
Natural Gas	-0.33	-0.00	-0.11	-0.10	0.00	0.00
Distillate Fuel Oil	-0.24	-0.13	-0.07	-0.06	0.00	0.00
Midwest						
Electricity	-0.08	-0.19	-0.04	-0.14	-0.10	-0.10
Natural Gas	-0.12	-0.05	-0.08	-0.08	0.00	0.00
Distillate Fuel Oil	-0.19	-0.06	-0.13	0.00	0.00	0.00
South						
Electricity	-0.12	-0.19	-0.03	-0.09	-0.10	-0.10
Natural Gas	-0.14	-0.09	-0.07	-0.11	0.00	0.00
Distillate Fuel Oil	-0.21	-0.02	-0.17	-0.22	0.00	0.00
West						
Electricity	-0.04	-0.19	-0.90	-0.10	-0.10	-0.10
Natural Gas	-0.17	-0.02	-0.09	-0.17	0.00	0.00
Distillate Fuel Oil	-0.10	0.00	-0.24	-0.35	0.00	0.00

Employment Elasticities	Heating	Cooling	Water Heating	Cooking	Lighting	Other Uses
Northeast	0.30	0.30	0.20	0.20	0.30	0.10
Midwest	0.30	0.30	0.20	0.20	0.10	0.10
South	0.30	0.30	0.20	0.20	0.10	0.10
West	0.30	0.30	0.20	0.20	0.10	0.10

Source: *The Demand for Energy in Commercial Buildings: An Analysis using NBECS Data*, Ronald J. Sutherland, Henry Clarius, Energy Information Administration Preliminary Draft, September 17, 1989.

Table A18. Capital Cost, Operating & Maintenance Cost, New Equipment Efficiency, Equipment Life, and Market Share by Service Type and Technology

	Heating								
	Gas Furnace			Oil Furnace			Electric Heat Pump		
Life Cycle Information	GFU1	GFU2	GFU3	OFU1	OFU2	OFU3	EHP1	EHP2	EHP3
Northeast									
Capital Cost 82$/MMBtu	19.23	22.89	23.22	20.35	21.99	25.67	54.37	65.95	77.76
O&M Cost 82$/MMBtu	0.77	0.92	0.93	0.81	0.88	1.03	2.17	2.64	3.11
Equipment Efficiency	0.72	0.81	0.92	0.71	0.80	0.90	1.47	1.80	2.10
Equipment Life - Years	23	23	23	23	23	23	23	23	23
Market Share	0.75	0.20	0.05	0.75	0.20	0.05	0.75	0.20	0.05
Midwest									
Capital Cost 82$/MMBtu	20.45	24.33	24.68	21.36	23.09	26.94	56.34	68.35	80.58
O&M Cost 82$/MMBtu	0.82	0.97	0.99	0.85	0.92	1.08	2.25	2.73	3.22
Equipment Efficiency	0.72	0.81	0.92	0.71	0.80	0.90	1.47	1.80	2.10
Equipment Life - Years	23	23	23	23	23	23	23	23	23
Market Share	0.75	0.20	0.05	0.75	0.20	0.05	0.75	0.20	0.05
South									
Capital Cost 82$/MMBtu	25.50	30.34	30.78	26.34	28.48	33.23	86.07	104.4	123.1
O&M Cost 82$/MMBtu	1.02	1.21	1.23	1.05	1.14	1.33	3.44	4.18	4.92
Equipment Efficiency	0.72	0.81	0.92	0.71	0.80	0.90	1.47	1.80	2.10
Equipment Life - Years	23	23	23	23	23	23	23	23	23
Market Share	0.75	0.20	0.05	0.75	0.20	0.05	0.75	0.20	0.05
West									
Capital Cost 82$/MMBtu	46.60	55.45	56.25	46.03	49.76	58.07	159.8	193.8	228.5
O&M Cost 82$/MMBtu	1.86	2.22	2.25	1.84	1.99	2.32	6.39	7.75	9.14
Equipment Efficiency	0.72	0.81	0.92	0.71	0.80	0.90	1.47	1.80	2.10
Equipment Life - Years	23	23	23	23	23	23	23	23	23
Market Share	0.75	0.20	0.05	0.75	0.20	0.05	0.75	0.20	0.05

See sources listed at end of table.

Table A18. Capital Cost, Operating & Maintenance Cost, New Equipment Efficiency, Equipment Life, and Market Share by Service Type and Technology (Continued)

	Cooling					
	Electric A/C			Electric Heat Pump		
Life Cycle Information	EAC1	EAC2	EAC3	EHP1	EHP2	EHP3
Northeast						
Capital Cost 82$/MMBtu . .	30.66	32.56	33.51	32.06	35.17	41.43
O&M Cost 82$/MMBtu . . .	1.23	1.30	1.34	1.28	1.41	1.66
Equipment Efficiency	3.10	3.20	3.70	2.20	2.30	2.60
Equipment Life - Years . . .	15	15	15	15	15	15
Market Share	0.38	0.10	0.02	0.38	0.10	0.02
Midwest						
Capital Cost 82$/MMBtu . .	29.78	31.63	32.55	31.96	35.06	41.30
O&M Cost 82$/MMBtu . . .	1.19	1.27	1.30	1.28	1.40	1.65
Equipment Efficiency	3.10	3.20	3.70	2.20	2.30	2.60
Equipment Life - Years . . .	15	15	15	15	15	15
Market Share	0.38	0.10	0.02	0.38	0.10	0.02
South						
Capital Cost 82$/MMBtu . .	11.88	12.62	12.99	10.39	11.40	13.43
O&M Cost 82$/MMBtu . . .	0.48	0.50	0.52	0.42	0.46	0.54
Equipment Efficiency	3.10	3.20	3.70	2.20	2.30	2.60
Equipment Life - Years . . .	15	15	15	15	15	15
Market Share	0.38	0.10	0.02	0.38	0.10	0.02
West						
Capital Cost 82$/MMBtu . .	17.65	18.75	19.29	17.44	19.13	22.54
O&M Cost 82$/MMBtu . . .	0.71	0.75	0.77	0.70	0.77	0.90
Equipment Efficiency	3.10	3.20	3.70	2.20	2.30	2.60
Equipment Life - Years . . .	15	15	15	15	15	15
Market Share	0.38	0.10	0.02	0.38	0.10	0.02

See sources listed at end of table.

Table A18. Capital Cost, Operating & Maintenance Cost, New Equipment Efficiency, Equipment Life, and Market Share by Service Type and Technology (Continued)

	Water Heating			
	Electric		Gas	
Life Cycle Information	E1	E2	G1	G2
All Regions				
Capital Cost 82$/MMBtu . .	5.85	6.99	6.28	7.02
Equipment Efficiency	0.77	0.93	0.66	0.89
Equipment Life - Years . . .	13	13	13	13
Market Share	0.75	0.25	0.75	0.25

	Lighting		
Life Cycle Information	Incandescent	Fluorescent	Fluorescent High Efficiency
All Regions			
Equipment Efficiency	0.36	0.84	1.00
Market Share	0.37	0.36	0.27

Sources: **Cooling.** ***Capital Cost*** - EPRI, the COMMEND computer program 3.0, Input Dataset, April 29, 1988; Air Conditioning and Refrigeration Institute, (ARI), *ARI Unitary Directory* Aug 1989 - Jan 1990. ***Capital Cost Regional Adjustments*** - GRI, *Topical Report #1: Data Enhancements for Commercial Sector Analysis of GRI Baseline Modeling Systems*, based on regional heating and cooling cost rates, July 1987, p. 130. ***Efficiency*** - GRI, *Topical Report #1: Data Enhancements for Commercial Sector Analysis of GRI Baseline Modeling Systems*, based on Energy Utilization Indices, July 1987, pp. 64-97; GRI, *Topical Report #1: Data Enhancements for Commercial Sector Analysis of GRI Baseline Modeling Systems*, July 1987, pp. 3-4. ***O&M Cost*** - GRI, *Topical Report #1: Data Enhancements for Commercial Sector Analysis of GRI Baseline Modeling Systems*, July 1987, p. 59. ***Equipment Life*** - Cohen, S., LBL, *Economics of Efficiency Improvements in Residential Appliances and Space Conditioning Equipment*, LBL-26952, VC-95d, Sept 1985, p. 9. **Water Heating.** ***Capital Cost*** - EPRI, The COMMEND Computer Program 3.0, Input Dataset, April 29, 1990. ***Efficiency*** - Cohen, S., LBL, *Economics of Efficiency Improvements in Residential Appliances and Space Conditioning Equipment*, LBL-26952, VC-95d, Sept 1985, p. 58; DOE, *Technical Support Document: In Support of Interim Energy Conservation Standards*, DOE/CE-0223, Vol. 2, June 1988, pp. 3.51, 3.52. ***Equipment Life*** - Cohen, S., LBL, *Economics of Efficiency Improvements in Residential Appliances and Space Conditioning Equipment*, LBL-26952, VC-95d, Sept 1985, p. 9. **Lighting.** LBL FOSSIL2 Dataset, (based on data for new structures, base case lighting).

Table A19. Benchmark Factors: SEDS Consumption by Region (Trillion Btu)

	Electricity	Natural Gas	Distillate Fuel Oil	Residual Oil	Liquefied Petroleum Gas	Coal	Motor Gasoline	Other
Northeast								
1985	438.2	458.0	198.9	121.3	6.7	25.0	19.2	4.2
1986	452.1	463.3	264.3	126.9	6.9	27.2	19.1	3.4
1987	476.8	466.4	245.4	124.9	7.8	27.6	16.7	3.4
Midwest								
1985	523.4	979.8	126.8	12.3	30.4	40.1	20.1	6.8
1986	531.8	907.7	88.2	17.8	31.3	42.2	28.2	2.7
1987	563.5	932.8	79.3	11.8	30.7	39.3	28.3	1.7
South								
1985	899.5	604.1	215.2	47.3	27.7	25.3	38.3	31.5
1986	955.1	593.5	161.0	81.3	26.1	24.8	40.6	24.7
1987	995.9	619.9	169.7	107.4	26.5	27.0	42.6	18.8
West								
1985	494.3	461.5	83.7	9.9	9.8	16.8	18.6	7.1
1986	521.8	418.1	82.2	22.3	8.6	12.8	18.5	10.7
1987	546.2	463.9	99.1	17.9	9.4	5.5	22.6	12.3

Source: Energy Information Administration, *State Energy Data Report Consumption Estimates*, 1960-1987, DOE/EIA-0214(87) (Washington, DC, April 1989).

Table A20. Benchmark Factors: STEO Consumption (Trillion Btu)

	1985	1986	1987	1988
Electricity	2374.6	2442.6	2529.4	2664.9
Natural Gas	2503.3	2382.6	2483.0	2753.8
Distillate Fuel Oil	624.6	595.6	593.5	621.0
Residual Oil	190.8	248.2	262.0	259.9
Liquefied Petroleum Gas	74.6	72.9	74.4	76.5
Coal	107.1	107.0	99.0	101.6
Motor Gasoline	96.1	106.3	110.2	112.5
Other	49.6	41.5	36.1	38.2

	Mid Case			High Demand Case			Low Demand Case		
	1989	1990	1991	1989	1990	1991	1989	1990	1991
Electricity	2778.0	2896.2	2896.2	2793.2	2920.3	2920.3	2765.3	2872.0	2872.0
Natural Gas	2698.3	2745.8	2745.8	2834.7	2745.8	2745.8	2596.5	2745.8	2745.8
Distillate Fuel Oil	588.8	592.6	592.6	602.6	594.7	594.7	577.8	590.7	590.7
Residual Oil	231.7	218.6	218.6	236.2	231.1	231.1	227.7	206.5	206.5
Liquefied Petroleum Gas	78.1	81.6	81.6	79.0	83.3	83.3	77.3	79.3	79.3
Coal	99.2	86.4	86.4	99.2	86.4	86.4	99.2	86.4	86.4
Motor Gasoline	112.3	113.3	113.3	112.4	114.2	114.2	112.3	112.5	112.5
Other	37.8	39.6	39.6	37.8	39.6	39.6	37.9	39.6	39.6

Source: Energy Information Administration, *Short Term Energy Outlook*, DOE/EIA-0202, (Washington, DC, Published Quarterly).

Appendix B

Coal Forecast Assumptions

Assumptions for the PC-Coal Model for the 1990 *Annual Energy Outlook*

- It is assumed that there are no capacity constraints on coal producers over the forecast period, with production meeting projected domestic demands and exports. This assumption refers to coal production, and not to production of alternative fuels which might be derived from coal, such as methanol. Separate assumptions in the appropriate demand sections are made with respect to such capacity.

- Delivered prices of coal are assumed to be the sum of minemouth costs and transportation markups.

- It is assumed that minemouth prices of coal are determined by their historic relationship to the quantity of production, labor productivity, and natural gas prices at the wellhead. A corollary assumption is that the fuel which competes most directly with coal, especially at the point of consumption, is natural gas. It is assumed that this competition will continue through the forecast period. It is also assumed that the level of coal prices will vary in the forecast period by region, based on historical differentials. No specific assumption on price differentials by sulfur content are made, but the use of historical data implicitly assumes that those differentials will continue through the forecast horizon. Table B1 shows the estimated parameters for the equation which defines the relationship.

- Transportation markups are assumed to be determined by their current (as of 1988) level, escalated by the rail transportation index escalator. That escalator, which is exogenous to the model, is in turn assumed to be determined by its historical relationship to wages, equipment costs, and fuel costs. Table B2 provides the index escalators and their associated input variables. Table B3 shows the markups.

- It is assumed that the distribution patterns for coal (from supply region to demand region/sector) will continue their 1980-1988 trends throughout the forecast period, but at a slower rate of change. The changes in distribution shares between 1988 and 2010 are assumed to approximate the changes experienced between 1980 and 1988. It is further assumed that the changing costs of developing mines and extracting coal will not significantly affect these patterns. The assumed pattern is displayed in Table B4.

- Producer and consumer stocks of coal are assumed to remain at constant days of supply (calculated as of the end of 1990) throughout the forecast period. Production of coal is assumed to be adjusted to maintain this equality.

- Labor productivity is assumed to increase 1 percent annually through 2000, and 0.5 percent annually from 2001 through 2010. This assumption is based upon a long-term examination of productivity trends and their relationship to changes in laws and regulations, structural changes, and technological change. It is assumed that there will be no major changes in these factors through the forecast period in the base case. In particular, it is assumed that penetration of longwall mining systems will not increase at as high a rate over the forecast period as they have in the 1980's, since opportunities for cost savings are leading to market saturation. And it is assumed that the high rate of closing of smaller, less efficient mines seen in the 1980's will slow significantly, since so few of those mines are now producing coal. Productivity by region by year is shown in Table B5.

- Coal exports and imports are assumed to be determined exogenously, through the International Coal Trade Model (ICTM). Detailed assumptions for the ICTM are given in a following section.

- Coal quality (in terms of heat content per ton) is assumed to remain constant from given supply regions over the forecast period. For utility coal, specific heat values are assigned to each supply region based on the most recent data. For other sectors, the quality of coal received by a particular demand region/sector is assumed to be the same from all supply regions. This is because for non-utility coal, the only quality data available is for receipts. It is assumed that the opening of new mines will keep aggregate quality constant, while quality of coal produced at existing mines will decline somewhat as a natural result of the mining process. Assumed heat content by sector by year is shown in Table B6.

Table B1. Estimated Regression Parameters for Minemouth Price Equation

Variable	Parameter Estimate	Standard Error	T-Value (b=0)
Intercept	3.6834	.2960	12.44*
Production	.2319	.0784	3.14*
Output/Manday	-.5024	.0568	-9.72*
Gas Price	.1666	.0465	3.91*
N. Appalachia	-.1989	.0934	-2.13*
S. Appalachia	-.2676	.1222	-2.19*
Interior	-.1617	.0721	-2.24*
Texas-Louis.	-.3025	.0636	-4.75*
North Dakota	-.1366	.1230	-1.11
Montana-Wyom.	-.1996	.0709	-2.81*
Durbin-Watson Statistic	1.889		
F-Ratio	587.12		
R Squared (Adjusted)	0.9886		

*Significant at a 95 % level of confidence.

Table B2. Mid Macro Coal Railroad Transportation Rate Escalation Factors

OBS	YEAR	WPI82	XWPI	CXTRI	CXTRI85	XXFCI	XXCNFI	XXALLO	XXWPLUS
1	1967	.	.	0.64804	0.65830	0.26768	0.70822	.	.
2	1968	.	.	0.65227	0.66260	0.26382	0.71285	.	.
3	1969	.	.	0.65643	0.66683	0.25763	0.71740	.	.
4	1970	7.0347	0.20673	0.68630	0.69717	0.25283	0.74399	.	.
5	1971	7.1281	0.20948	0.70056	0.71165	0.24803	0.77249	.	.
6	1972	6.9157	0.20324	0.72846	0.73999	0.24200	0.80595	.	.
7	1973	8.2241	0.24169	0.76844	0.78061	0.26499	0.84802	.	.
8	1974	23.1431	0.68012	0.80478	0.81753	0.48404	0.85222	.	.
9	1975	21.0446	0.61845	0.83407	0.84728	0.52164	0.87381	.	.
10	1976	21.3250	0.62669	0.86790	0.88165	0.53318	0.91225	.	.
11	1977	21.5544	0.63343	0.88288	0.89686	0.55630	0.92521	.	.
12	1978	20.1440	0.59199	0.89385	0.90800	0.54157	0.94200	.	.
13	1979	27.5695	0.81021	0.93502	0.94983	0.74139	0.94940	.	.
14	1980	40.1121	1.17881	0.97134	0.98673	1.01833	0.96488	1.01576	0.92580
15	1981	39.9771	1.17484	0.99683	1.01261	1.11601	0.98169	1.02000	0.95171
16	1982	34.0278	1.00000	1.00000	1.01584	1.00000	1.00000	1.00000	1.00000
17	1983	28.6345	0.84150	1.00364	1.01953	0.83671	1.02599	0.98009	1.06159
18	1984	27.1492	0.79785	1.00243	1.01831	0.79745	1.02968	0.96858	1.07807
19	1985	24.6630	0.72479	0.98441	1.00000	0.72349	1.01590	0.95098	1.06112
20	1986	12.4705	0.36648	0.96750	0.98282	0.45532	1.02756	0.94655	1.08447
21	1987	15.6239	0.45915	0.96769	0.98301	0.47006	1.02628	0.99385	1.10018
22	1988	12.2004	0.35854	0.98686	1.00249	0.41084	1.05319	1.02420	1.12794
23	1989	13.8208	0.40616	0.99122	1.00692	0.42942	1.01017	0.96211	1.03513
24	1990	12.9471	0.38049	0.98721	1.00285	0.40390	1.01078	0.95933	1.03742
25	1991	12.7882	0.37582	0.98876	1.00442	0.39925	1.01351	0.96499	1.04328
26	1992	13.1059	0.38515	0.99103	1.00673	0.40855	1.01415	0.96339	1.04535
27	1993	14.2974	0.42017	0.99795	1.01375	0.44330	1.01507	0.96184	1.04817
28	1994	15.4094	0.45285	1.00425	1.02015	0.47557	1.01620	0.96101	1.05139
29	1995	16.2037	0.47619	1.00895	1.02493	0.49853	1.01747	0.96045	1.05492
30	1996	17.3952	0.51120	1.01546	1.03154	0.53285	1.01907	0.96010	1.05928
31	1997	18.6660	0.54855	1.02191	1.03810	0.56929	1.02061	0.95939	1.06356
32	1998	20.0164	0.58824	1.02830	1.04458	0.60785	1.02207	0.95875	1.06764
33	1999	21.2078	0.62325	1.03385	1.05022	0.64173	1.02354	0.95838	1.07170
34	2000	22.0815	0.64893	1.03854	1.05499	0.66650	1.02543	0.95809	1.07688
35	2001	23.0347	0.67694	1.04321	1.05974	0.69346	1.02714	0.95658	1.08188
36	2002	23.8290	0.70028	1.04755	1.06414	0.71587	1.02913	0.95487	1.08769
37	2003	24.7027	0.72596	1.05216	1.06882	0.74047	1.03122	0.95309	1.09386
38	2004	25.4176	0.74697	1.05671	1.07345	0.76056	1.03384	0.95171	1.10138
39	2005	26.1325	0.76797	1.06119	1.07800	0.78061	1.03643	0.94979	1.10899
40	2006	26.8473	0.78898	1.06579	1.08267	0.80062	1.03919	0.94783	1.11712
41	2007	27.5622	0.80999	1.07033	1.08728	0.82061	1.04194	0.94594	1.12522
42	2008	28.1976	0.82867	1.07468	1.09170	0.83835	1.04474	0.94402	1.13355
43	2009	28.7537	0.84500	1.07877	1.09586	0.85385	1.04753	0.94194	1.14190
44	2010	29.3097	0.86134	1.08268	1.09982	0.86933	1.05014	0.93940	1.14991

Key: WPI82 = world oil prices in 1982 dollars per barrel; XWPI = world oil price index; CXTRI = railroad composite rate escalation factor based at 1982; CXTRI85 = railroad composite rate escalation factor base at 1985; XXFCI = railroad fuel cost index; XXCNFI = railroad nonfuel cost index; XXALLO = railroad all other operating cost index; XXWPLUS = railroad wage-plus-wage supplements cost index.

Table B3. Price Markups From Supply Region to Demand Region and Sector (1990 Price Markups, 1982 Dollars per Ton)

	Supply Region						
Demand Region and Sector	North Appal	South Appal	Interior	Texas Louisiana	North Dakota	Montana Wyoming	Western
Northeast							
Residential/ Commercial	20.30	20.86	0.00	0.00	0.00	0.00	0.00
Other Industrial	9.22	9.78	0.00	0.00	0.00	0.00	0.00
Utility	7.06	7.62	0.00	0.00	0.00	0.00	0.00
Metallurgic	12.38	12.94	0.00	0.00	0.00	0.00	0.00
North Central							
Residential/ Commercial	15.62	16.18	18.18	0.00	33.71	32.10	21.68
Other Industrial	0.07	0.64	2.64	0.00	18.17	16.56	6.14
Utility	0.24	0.80	2.80	0.00	18.34	16.73	6.30
Metallurgic	18.06	18.63	20.63	0.00	0.00	0.00	0.00
South							
Residential/ Commercial	8.36	8.92	10.92	0.00	0.00	0.00	14.42
Other Industrial	6.08	6.64	8.64	20.70	0.00	22.56	12.14
Utility	3.17	3.73	5.73	17.78	0.00	19.65	9.23
Metallurgic	12.98	13.55	0.00	0.00	0.00	0.00	0.00
West							
Residential/ Commercial	0.00	12.33	0.00	0.00	0.00	28.25	17.83
Other Industrial	0.00	4.77	6.77	0.00	0.00	20.69	10.27
Utility	0.00	0.00	0.00	0.00	0.00	10.08	-0.34
Metallurgic	0.00	14.39	0.00	0.00	0.00	0.00	19.89

Note: Zero markup indicates no tonnage projected for the origin/destination pair.

Table B3. Price Markups From Supply Region to Demand Region and Sector (Continued) (1995 Price Markups, 1982 Dollars per Ton)

	Supply Region						
Demand Region and Sector	North Appal	South Appal	Interior	Texas Louisiana	North Dakota	Montana Wyoming	Western
Northeast							
Residential/ Commercial	20.75	21.32	0.00	0.00	0.00	0.00	0.00
Other Industrial	9.42	10.00	0.00	0.00	0.00	0.00	0.00
Utility	7.22	7.79	0.00	0.00	0.00	0.00	0.00
Metallurgic	12.65	13.23	0.00	0.00	0.00	0.00	0.00
North Central							
Residential/ Commercial	15.96	16.54	18.58	0.00	34.46	32.81	22.16
Other Industrial	0.08	0.65	2.70	0.00	18.57	16.93	6.27
Utility	0.25	0.82	2.87	0.00	18.74	17.09	6.44
Metallurgic	18.46	19.04	21.08	0.00	0.00	0.00	0.00
South							
Residential/ Commercial	8.54	9.12	11.16	0.00	0.00	0.00	14.74
Other Industrial	6.21	6.79	8.83	21.15	0.00	23.06	12.41
Utility	3.23	3.81	5.86	18.17	0.00	20.08	9.43
Metallurgic	13.27	13.84	0.00	0.00	0.00	0.00	0.00
West							
Residential/ Commercial	0.00	12.60	0.00	0.00	0.00	28.87	18.22
Other Industrial	0.00	4.88	6.92	0.00	0.00	21.15	10.50
Utility	0.00	0.00	0.00	0.00	0.00	10.30	-0.35
Metallurgic	0.00	14.71	0.00	0.00	0.00	0.00	20.33

Note: Zero markup indicates no tonnage projected for the origin/destination pair.

Table B3. Price Markups From Supply Region to Demand Region and Sector (Continued) (2000 Price Markups, 1982 Dollars per Ton)

Demand Region and Sector	Supply Region North Appal	 South Appal	 Interior	 Texas Louisiana	 North Dakota	 Montana Wyoming	 Western
Northeast							
Residential/ Commercial	21.36	21.95	0.00	0.00	0.00	0.00	0.00
Other Industrial	9.70	10.29	0.00	0.00	0.00	0.00	0.00
Utility	7.43	8.02	0.00	0.00	0.00	0.00	0.00
Metallurgic	13.02	13.62	0.00	0.00	0.00	0.00	0.00
North Central							
Residential/ Commercial	16.43	17.02	19.13	0.00	35.47	33.77	22.81
Other Industrial	0.08	0.67	2.78	0.00	19.12	17.42	6.46
Utility	0.25	0.85	2.95	0.00	19.29	17.60	6.63
Metallurgic	19.00	19.59	21.70	0.00	0.00	0.00	0.00
South							
Residential/ Commercial	8.80	9.39	11.49	0.00	0.00	0.00	15.17
Other Industrial	6.39	6.99	9.09	21.77	0.00	23.74	12.77
Utility	3.33	3.92	6.03	18.71	0.00	20.67	9.71
Metallurgic	13.66	14.25	0.00	0.00	0.00	0.00	0.00
West							
Residential/ Commercial	0.00	12.97	0.00	0.00	0.00	29.72	18.75
Other Industrial	0.00	5.02	7.12	0.00	0.00	21.77	10.80
Utility	0.00	0.00	0.00	0.00	0.00	10.60	-0.36
Metallurgic	0.00	15.14	0.00	0.00	0.00	0.00	20.93

Note: Zero markup indicates no tonnage projected for the origin/destination pair.

Table B3. Price Markups From Supply Region to Demand Region and Sector (Continued) (2005 Price Markups, 1982 Dollars per Ton)

	Supply Region						
Demand Region and Sector	North Appal	South Appal	Interior	Texas Louisiana	North Dakota	Montana Wyoming	Western
Northeast							
Residential/ Commercial	21.82	22.43	0.00	0.00	0.00	0.00	0.00
Other Industrial	9.91	10.52	0.00	0.00	0.00	0.00	0.00
Utility	7.59	8.20	0.00	0.00	0.00	0.00	0.00
Metallurgic	13.31	13.91	0.00	0.00	0.00	0.00	0.00
North Central							
Residential/ Commercial	16.79	17.39	19.54	0.00	36.24	34.51	23.30
Other Industrial	0.08	0.69	2.84	0.00	19.53	17.80	6.60
Utility	0.26	0.86	3.01	0.00	19.71	17.98	6.77
Metallurgic	19.42	20.02	22.17	0.00	0.00	0.00	0.00
South							
Residential/ Commercial	8.99	9.59	11.74	0.00	0.00	0.00	15.50
Other Industrial	6.53	7.14	9.29	22.25	0.00	24.26	13.05
Utility	3.40	4.01	6.16	19.11	0.00	21.12	9.92
Metallurgic	13.95	14.56	0.00	0.00	0.00	0.00	0.00
West							
Residential/ Commercial	0.00	13.25	0.00	0.00	0.00	30.37	19.16
Other Industrial	0.00	5.13	7.28	0.00	0.00	22.24	11.04
Utility	0.00	0.00	0.00	0.00	0.00	10.83	-0.37
Metallurgic	0.00	15.47	0.00	0.00	0.00	0.00	21.38

Note: Zero markup indicates no tonnage projected for the origin/destination pair.

Table B3. Price Markups From Supply Region to Demand Region and Sector (Continued)
(2010 Price Markups, 1982 Dollars per Ton)

Demand Region and Sector	Supply Region: North Appal	South Appal	Interior	Texas Louisiana	North Dakota	Montana Wyoming	Western
Northeast							
Residential/ Commercial	22.26	22.88	0.00	0.00	0.00	0.00	0.00
Other Industrial	10.11	10.73	0.00	0.00	0.00	0.00	0.00
Utility	7.74	8.36	0.00	0.00	0.00	0.00	0.00
Metallurgic	13.58	14.19	0.00	0.00	0.00	0.00	0.00
North Central							
Residential/ Commercial	17.13	17.75	19.94	0.00	36.97	35.21	23.78
Other Industrial	0.08	0.70	2.89	0.00	19.93	18.16	6.73
Utility	0.26	0.88	3.08	0.00	20.11	18.34	6.91
Metallurgic	19.81	20.43	22.62	0.00	0.00	0.00	0.00
South							
Residential/ Commercial	9.17	9.79	11.98	0.00	0.00	0.00	15.82
Other Industrial	6.67	7.29	9.48	22.70	0.00	24.75	13.32
Utility	3.47	4.09	6.28	19.50	0.00	21.55	10.12
Metallurgic	14.24	14.86	0.00	0.00	0.00	0.00	0.00
West							
Residential/ Commercial	0.00	13.52	0.00	0.00	0.00	30.98	19.55
Other Industrial	0.00	5.23	7.43	0.00	0.00	22.69	11.26
Utility	0.00	0.00	0.00	0.00	0.00	11.05	-0.38
Metallurgic	0.00	15.79	0.00	0.00	0.00	0.00	21.82

Note: Zero markup indicates no tonnage projected for the origin/destination pair.

Table B4. Supply Distribution From Supply Region to Demand region and Sector (1990 Supply Distribution, Million Short Tons)

	Supply Region						
Demand Region and Sector	North Appal	South Appal	Interior	Texas Louisiana	North Dakota	Montana Wyoming	Western
Northeast							
Residential/ Commercial	1.71	0.07	0.00	0.00	0.00	0.00	0.00
Other Industrial	5.58	0.82	0.00	0.00	0.00	0.00	0.00
Utility	53.66	6.14	0.00	0.00	0.00	0.00	0.00
Metallurgic	5.09	5.66	0.00	0.00	0.00	0.00	0.00
North Central							
Residential/ Commercial	0.53	0.42	0.99	0.00	0.11	0.34	0.01
Other Industrial	3.27	9.00	11.02	0.00	6.66	1.78	0.07
Utility	36.09	37.12	77.30	0.00	25.66	97.06	0.41
Metallurgic	1.72	16.11	1.67	0.00	0.00	0.00	0.00
South							
Residential/ Commercial	0.17	1.07	0.14	0.00	0.00	0.00	0.01
Other Industrial	2.41	22.72	1.35	2.91	0.00	0.78	0.50
Utility	34.71	120.92	52.38	57.87	0.00	70.69	1.86
Metallurgic	0.97	9.33	0.00	0.00	0.00	0.00	0.00
West							
Residential/ Commercial	0.00	0.00	0.00	0.00	0.00	0.12	0.37
Other Industrial	0.00	0.13	0.00	0.00	0.00	2.61	4.75
Utility	0.00	0.00	0.00	0.00	0.00	39.38	60.18
Metallurgic	0.00	0.15	0.00	0.00	0.00	0.00	0.72

Table B4. Supply Distribution From Supply Region to Demand region and Sector (Continued) (1995 Supply Distribution, Million Short Tons)

Demand Region and Sector	Supply Region						
	North Appal	South Appal	Interior	Texas Louisiana	North Dakota	Montana Wyoming	Western
Northeast							
Residential/ Commercial	1.67	0.08	0.00	0.00	0.00	0.00	0.00
Other Industrial	5.71	0.94	0.00	0.00	0.00	0.00	0.00
Utility	55.92	6.90	0.00	0.00	0.00	0.00	0.00
Metallurgic	5.18	5.89	0.00	0.00	0.00	0.00	0.00
North Central							
Residential/ Commercial	0.51	0.39	0.96	0.00	0.09	0.33	0.00
Other Industrial	2.70	9.11	10.58	0.00	7.53	1.87	0.06
Utility	38.49	41.70	82.45	0.00	28.67	107.94	0.44
Metallurgic	1.65	16.91	1.53	0.00	0.00	0.00	0.00
South							
Residential/ Commercial	0.17	1.00	0.13	0.00	0.00	0.00	0.01
Other Industrial	2.44	23.76	1.19	2.96	0.00	0.84	0.51
Utility	38.38	133.08	58.12	66.49	0.00	79.80	1.80
Metallurgic	0.82	9.79	0.00	0.00	0.00	0.00	0.00
West							
Residential/ Commercial	0.00	0.00	0.00	0.00	0.00	0.12	0.36
Other Industrial	0.00	0.15	0.00	0.00	0.00	2.75	4.97
Utility	0.00	0.00	0.00	0.00	0.00	44.72	67.35
Metallurgic	0.00	0.16	0.00	0.00	0.00	0.00	0.74

Table B4. Supply Distribution From Supply Region to Demand region and Sector (Continued) (2000 Supply Distribution, Million Short Tons)

	Supply Region						
Demand Region and Sector	North Appal	South Appal	Interior	Texas Louisiana	North Dakota	Montana Wyoming	Western
Northeast							
Residential/ Commercial	1.47	0.09	0.00	0.00	0.00	0.00	0.00
Other Industrial	5.87	1.08	0.00	0.00	0.00	0.00	0.00
Utility	58.47	7.75	0.00	0.00	0.00	0.00	0.00
Metallurgic	4.73	5.49	0.00	0.00	0.00	0.00	0.00
North Central							
Residential/ Commercial	0.45	0.33	0.85	0.00	0.07	0.30	0.00
Other Industrial	2.14	9.31	10.22	0.00	8.48	1.98	0.05
Utility	39.68	45.27	84.99	0.00	30.97	116.06	0.45
Metallurgic	1.41	15.89	1.23	0.00	0.00	0.00	0.00
South							
Residential/ Commercial	0.16	0.88	0.11	0.00	0.00	0.00	0.01
Other Industrial	2.49	24.95	1.03	3.01	0.00	0.91	0.53
Utility	39.91	137.73	60.65	71.77	0.00	84.71	1.62
Metallurgic	0.60	9.19	0.00	0.00	0.00	0.00	0.00
West							
Residential/ Commercial	0.00	0.00	0.00	0.00	0.00	0.11	0.32
Other Industrial	0.00	0.18	0.00	0.00	0.00	2.99	5.36
Utility	0.00	0.00	0.00	0.00	0.00	54.98	81.61
Metallurgic	0.00	0.16	0.00	0.00	0.00	0.00	0.67

Table B4. Supply Distribution From Supply Region to Demand region and Sector (Continued) (2005 Supply Distribution, Million Short Tons)

Demand Region and Sector	North Appal	South Appal	Interior	Texas Louisiana	North Dakota	Montana Wyoming	Western
	Supply Region						
Northeast							
Residential/ Commercial	1.30	0.09	0.00	0.00	0.00	0.00	0.00
Other Industrial	6.42	1.31	0.00	0.00	0.00	0.00	0.00
Utility	80.98	11.49	0.00	0.00	0.00	0.00	0.00
Metallurgic	4.31	5.12	0.00	0.00	0.00	0.00	0.00
North Central							
Residential/ Commercial	0.40	0.29	0.76	0.00	0.06	0.27	0.00
Other Industrial	1.66	10.08	10.44	0.00	10.01	2.22	0.04
Utility	44.77	53.78	95.88	0.00	36.62	136.60	0.51
Metallurgic	1.20	14.93	0.97	0.00	0.00	0.00	0.00
South							
Residential/ Commercial	0.15	0.77	0.09	0.00	0.00	0.00	0.01
Other Industrial	2.66	27.61	0.90	3.24	0.00	1.03	0.57
Utility	44.29	152.13	67.55	82.60	0.00	95.95	1.50
Metallurgic	0.40	8.63	0.00	0.00	0.00	0.00	0.00
West							
Residential/ Commercial	0.00	0.00	0.00	0.00	0.00	0.10	0.28
Other Industrial	0.00	0.23	0.00	0.00	0.00	3.52	6.27
Utility	0.00	0.00	0.00	0.00	0.00	65.96	96.51
Metallurgic	0.00	0.15	0.00	0.00	0.00	0.00	0.61

Table B4. Supply Distribution From Supply Region to Demand region and Sector (Continued) (2010 Supply Distribution, Million Short Tons)

Demand Region and Sector	Supply Region						
	North Appal	South Appal	Interior	Texas Louisiana	North Dakota	Montana Wyoming	Western
Northeast							
Residential/ Commercial	1.14	0.09	0.00	0.00	0.00	0.00	0.00
Other Industrial	7.31	1.64	0.00	0.00	0.00	0.00	0.00
Utility	102.78	15.55	0.00	0.00	0.00	0.00	0.00
Metallurgic	3.93	4.77	0.00	0.00	0.00	0.00	0.00
North Central							
Residential/ Commercial	0.36	0.25	0.68	0.00	0.04	0.24	0.00
Other Industrial	1.35	13.23	12.91	0.00	14.21	3.01	0.04
Utility	49.09	62.11	105.14	0.00	42.09	156.36	0.55
Metallurgic	1.01	14.02	0.75	0.00	0.00	0.00	0.00
South							
Residential/ Commercial	0.14	0.67	0.08	0.00	0.00	0.00	0.01
Other Industrial	3.04	32.61	0.78	3.71	0.00	1.26	0.66
Utility	50.33	172.05	77.04	97.27	0.00	111.27	1.37
Metallurgic	0.23	8.10	0.00	0.00	0.00	0.00	0.00
West							
Residential/ Commercial	0.00	0.00	0.00	0.00	0.00	0.09	0.25
Other Industrial	0.00	0.32	0.00	0.00	0.00	4.46	7.88
Utility	0.00	0.00	0.00	0.00	0.00	76.65	110.56
Metallurgic	0.00	0.15	0.00	0.00	0.00	0.00	0.56

Table B5. Productivity by Supply Region and Year
(Productivity in Tons per Man-Day)

Supply Region	1990	1991	1992	1993	1994	1995	1996
Northern Appalachia	21.56	21.75	21.95	22.14	22.34	22.54	22.75
Southern Appalachia	22.66	22.87	23.08	23.29	23.50	23.72	23.94
Interior	29.62	29.88	30.15	30.42	30.69	30.96	31.24
Texas-Louisiana	72.46	72.89	73.33	73.77	74.21	74.66	75.12
North Dakota	140.56	141.98	143.43	144.88	146.35	147.84	149.34
Montana-Wyoming	189.61	191.97	194.35	196.76	199.19	201.65	204.13
Western	42.72	43.04	43.35	43.67	43.99	44.32	44.65
NATIONAL	34.05	34.39	34.74	35.08	35.43	35.79	36.15

Supply Region	1997	1998	1999	2000	2001	2002	2003
Northern Appalachia	22.95	23.16	23.36	23.57	23.68	23.79	23.89
Southern Appalachia	24.16	24.39	24.61	24.84	24.96	25.07	25.19
Interior	31.52	31.80	32.09	32.38	32.52	32.67	32.82
Texas-Louisiana	75.58	76.04	76.51	76.98	77.22	77.46	77.70
North Dakota	150.86	152.39	153.93	155.49	156.28	157.08	157.87
Montana-Wyoming	206.64	209.17	211.73	214.31	215.61	216.92	218.24
Western	44.98	45.31	45.65	45.99	46.16	46.34	46.51
NATIONAL	36.51	36.87	37.24	37.61	37.80	37.99	38.18

Supply Region	2004	2005	2006	2007	2008	2009	2010
Northern Appalachia	24.00	24.11	24.22	24.33	24.44	24.55	24.66
Southern Appalachia	25.30	25.42	25.54	25.66	25.78	25.90	26.02
Interior	32.96	33.11	33.26	33.41	33.56	33.71	33.87
Texas-Louisiana	77.94	78.19	78.43	78.68	78.93	79.17	79.42
North Dakota	158.67	159.48	160.29	161.10	161.91	162.74	163.56
Montana-Wyoming	219.56	220.89	222.23	223.57	224.92	226.28	227.64
Western	46.69	46.86	47.04	47.22	47.40	47.58	47.76
NATIONAL	38.37	38.56	38.76	38.95	39.14	39.34	39.54

Table B6. Heat Content by Demand Sector and Region (Average Btu per Ton)

Demand Sector and Region	1990	1995	2000	2005	2010
Residential/Commercial					
Northeast	25.3893	25.3893	25.3893	25.3893	25.3893
North Central	22.0197	22.0197	22.0197	22.0197	22.0197
South	24.9030	24.9030	24.9030	24.9030	24.9030
West	21.4505	21.4505	21.4505	21.4505	21.4505
Other Industrial					
Northeast	25.0910	25.0910	25.0910	25.0910	25.0910
North Central	21.2210	21.2210	21.2210	21.2210	21.2210
South	23.4490	23.4490	23.4490	23.4490	23.4490
West	20.7824	20.7824	20.7824	20.7824	20.7824
Utility					
Northeast	24.9814	24.9928	25.0042	25.0156	25.0270
North Central	20.3466	20.3082	20.2699	20.2317	20.1937
South	20.9565	20.8795	20.8030	20.7271	20.6517
West	19.2856	19.2746	19.2635	19.2525	19.2414
Metallurgic					
Northeast	26.8000	26.8000	26.8000	26.8000	26.8000
North Central	26.8000	26.8000	26.8000	26.8000	26.8000
South	26.8000	26.8000	26.8000	26.8000	26.8000
West	26.8000	26.8000	26.8000	26.8000	26.8000
Residential/Commercial	23.6263	23.6313	23.6324	23.6336	23.6348
Other Industrial	22.3973	22.4112	22.4188	22.4198	22.3535
Utility	20.8365	20.7708	20.6925	20.7033	20.7033
Metallurgic	26.8000	26.8000	26.8000	26.8000	26.8000
Average	21.2282	21.1329	21.0148	20.9044	20.8681

Appendix C

Electricity and Nuclear Technologies: Assumptions and Methodologies

Generating Plant Types

The following plant types reflecting current technology are available for the analysis:

1. Coal-fired Steam
2. Gas-fired Steam
3. Oil-fired Steam
4. Gas/Oil fired Steam
5. Gas-fired Combined Cycle
6. Oil-fired Combined Cycle
7. Gas-fired Combustion Turbine
8. Oil-fired Combustion Turbine
9. Gas/Oil-fired Combustion Turbine
10. Nuclear
11. Pumped Storage
12. Hydroelectric/Other (includes pondage hydroelectric power and other sources such as geothermal power, wood, waste, solar energy and wind.

Fuels Used to Generate Electricity

The following fuels are included in electric utility analysis:

1. Coal
2. Natural Gas
3. Distillate Fuel Oil
4. Low Sulfur Residual Fuel Oil
5. High Sulfur Residual Fuel Oil
6. Uranium

Transmission and Distribution Losses

Transmission and Distribution losses are specified by Federal Region. They range from 7 to 8.5 percent.

Existing and New Plant Capabilities

The source of data for non-nuclear plants is the form EIA-860, *Annual Electric Generator Report*. Existing capacity is specified using net summer capability. A listing of nuclear units remaining in the construction pipeline, their net summer capabilities, and estimated operable dates are provided in Table C1. Four units (Perry 2, Shoreham, and WNP 1 and 3) are assumed not to become operable during the projected period. Unit operable dates have been adjusted from utility estimates based on information concerning construction progress, licensing status, and financial condition of the utility.

Table C1 also contains information about several units which are projected to retire. These retirement dates are based on an assumed 40-year operating life. Fort St. Vrain retired in 1989. Hanford-N, officially in a cold standby status, is treated as retired in 1988, and Rancho Seco is treated as retired in 1989.

The cumulative operable capability (net GWe) for 5-year intervals beginning in 1985 is compared to the previous *AEO* below:

Operable Capability (net GWe)

Year	AEO89	AEO90
1985	79.5	79.5
1990	99.9	99.3
1995	103.0	102.8
2000	104.0	103.8
2005	--	103.8
2010	--	99.7

Environmental Standards

Current environmental laws are included. These include standards to meet State Implementation Plans (SIP); New Source Performance Standards (NSPS), Revised New Source Performance Standards (RNSPS), and Prevention of Significant Deterioration (PSD).

Capacity Factors

Actual capacity factors for fossil plants are determined by economic dispatch. Except for partially life extended plants, the assumed maximum capacity factor achievable for each plant is based on its highest historial capacity factor or 68 percent, whichever is greater. The maximum capacity factor achievable for partially life extended plants is restricted to 40 percent after their 25th year of operation.

There are separate capacity factor assumptions for the first fuel cycle and remaining or equilibrium cycles for nuclear power plants. The first cycle extends for nine quarters (2.25 years) and has an average capacity factor of 55 percent. This is an increase over the value of 50 percent previously assumed. The average equilibrium cycle capacity factor values are disaggregated by Federal Region. Table C2 contains the average annual capacity factors projected for nuclear units in 1989 through 2010. These capacity factors are estimated by dividing existing boiling water reactors into four categories with capacity factors of 51, 55, 60 and 70 percent. Existing pressurized water reactors are divided into five categories with capacity factors of 51, 63, 69, 74 and 83 percent. These values are applied in the initial model year and gradually increased through 2010. The average capacity factors for the United States resulting from these values increase from about 61 percent in 1989 to about 68 percent in 2010.

Efficiencies for Fossil-Fuel Plants

In each forecast year, efficiencies for existing fossil fuel plants are assumed to be the average of the efficiencies observed during 1982-1987. In 1987, the efficiency of existing Coal-fired and Oil-fired plants was 33 percent and the efficiency of Gas-fired steam plants was 32 percent. Assumptions for efficiency rates for new generating units are shown in Table C3. (NOTE: Revisions in coal-fired efficiencies are possible, pending results of aging study being conducted by the Office of Fossil Energy and EIA.)

Table C1. Nuclear Unit Capacities and Operable and Retirement Dates

Unit	Net Summer Capability (MWe)	Operable/ Retirement Date	Cumulative Capacity (MWe)
108 Reactors			
Total, 1988	--	--	94,695
South Texas 2	1,250	4/89	
Vogtle 2	1,086	3/89	
Rancho Seco	(873)	6/89 (Retirement)	
Fort St. Vrain	(217)	8/89	
Limerick 2	1,055	9/89	
Total, 1989	2,301		96,996
Comanche Peak 1	1,150	3/90	
Seabrook 1	1,150	6/90	
Total, 1990	2,300		99,296
Comanche Peak 2	1,150	3/92	
Watts Bar 1	1,170	6/92	
Total, 1992	2,320		101,616
Watts Bar 2	1,170	3/95	
Total, 1995	1,170		102,786
Bellefonte 1	1,212	6/2000	
Yankee Rowe	(167)	8/2000	
Total, 2000	1,045		103,831
Big Rock Point	(67)	3/2003	
Total, 2003	(67)		103,764
Total, 2005	--		103,764
San Onofre	(436)	4/2007	
Haddam Neck	(565)	6/2007	
Total, 2007	(1,001)		102,763
Bellefonte 2	1,212	6/2009	
Oyster Creek 1	(620)	8/2009	
Nine Mile Point 1	(610)	8/2009	
Ginna	(470)	9/2009	
Dresden 2	(772)	12/2009	
Total, 2009	(1,260)		101,503
Robinson 2	(665)	9/2010	
Point Beach 1	(485)	10/2010	
Millstone 1	(652)	10/2010	
Total, 2010	(1,802)		99,701

Sources: Nuclear and Alternate Fuels Division; capacities derived from EIA-860 survey.

Table C2. Nuclear Equilibrium Cycle Capacity Factor Assumptions by Region (Percent)

Year	Federal Region 1	2	3	4	5	6	7	8	9	10
1989	67.2	56.6	59.4	62.1	59.7	57.6	62.6	0	66.4	58.4
1990	59.4	57.4	61.8	62.1	61.5	56.9	61.3	0	65.3	57.2
1991	63.7	57.9	61.9	62.7	62.5	65.8	63.1	0	67.2	58.8
1992	64.3	57.1	62.0	60.6	61.7	64.5	62.5	0	66.5	58.3
1993	65.7	57.3	62.8	61.8	61.9	65.3	61.5	0	65.4	57.2
1994	65.4	57.0	62.5	61.8	61.6	66.9	61.3	0	65.3	57.2
1995	65.6	57.3	62.7	61.6	61.8	66.6	60.7	0	64.6	56.6
1996	65.9	57.4	62.9	62.2	62.0	66.8	60.9	0	64.8	56.8
1997	66.1	57.6	63.1	62.9	62.2	67.0	61.1	0	65.0	56.9
1998	66.7	58.1	63.7	63.6	62.8	67.7	61.6	0	65.6	57.5
1999	66.5	58.0	63.6	63.5	62.7	67.5	61.5	0	65.5	57.4
2000	66.6	58.2	63.8	62.3	62.9	67.7	61.7	0	65.7	57.5
2001	66.9	58.5	64.1	63.6	63.2	68.1	62.0	0	66.1	57.8
2002	67.3	58.8	64.4	63.6	63.5	68.4	62.3	0	66.4	58.1
2003	67.6	59.1	64.8	64.4	63.9	68.8	62.7	0	66.7	58.4
2004	68.0	59.4	65.1	64.7	64.2	69.1	63.0	0	67.1	58.7
2005	68.3	59.7	65.4	65.1	64.5	69.5	63.3	0	67.4	59.0
2006	68.6	60.0	65.7	65.4	64.8	69.8	63.6	0	67.7	59.3
2007	68.7	60.3	66.1	65.7	65.1	70.2	63.9	0	69.8	59.6
2008	68.8	60.6	66.4	66.0	65.4	70.5	64.2	0	69.3	59.9
2009	69.1	60.6	66.7	65.0	68.1	70.8	64.6	0	69.7	60.2
2010	69.6	60.7	67.6	67.8	66.3	71.7	65.4	0	70.6	61.0

Source: Nuclear and Alternate Fuels Division.

Table C3. Heat Rates for New Generating Units (Percent)

Plant Type	Heat Rate Btu/Kilowatthour
Noncoal Fossil-Fired Steam	9,680
Coal-Fired Steam with Flue Gas Desulfurization	
Bituminous	10,060
Subbituminous	10,070
Lignite	10,150
Combined Cycle	8,140
Combustion Turbine	13,100

Source: Electric Power Research Institute, *Technical Assessment Guide* (1986).

Operations and Maintenance (O&M) Costs

The O&M costs for fossil and hydroelectric plants are shown below in 1988 dollars.

Plant Type	Fixed Cost ($/KW/YR)	Variable Cost ($/MKWH)
Coal Steam w/o FGD		
Bituminous	15.0	1.6
Subbituminous	14.8	1.0
Lignite	12.0	1.0
Coal Steam w/ FGD		
Bituminous	26.6	6.1
Subbituminous	26.2	3.9
Lignite	22.0	3.8
Oil-Fired Steam	5.4	5.3
Gas-Fired Steam	4.5	4.4
Combined Cycle	7.3	1.9
Combustion Turbine	0.4	4.4
Pondage Hydroelectric	5.5	1.8
Pumped Storage	4.7	4.7

Sources: Coal -- OMCOST Model:O&M Costs for Coal vary depending on the Btu and sulfur content. Other -- EPRI, "1986 Technical Assessment Guide. Costs for coal steam plants without FGD were determined using FGD costs from Stearns-Rogers Engineering Corporation, *Economic Evaluation of FGD Systems,* Volume 1, "Throwaway FGD Processes, High- and Low-Sulfur Coal" (Palo Alto, California, December 1983).

The estimated non-fuel O&M costs for nuclear plants are shown below (in 1987 dollars).

Federal Region	Fixed Component ($/KWe)	Variable Component (Mills/kWh)	Total (Mills/kWh)
1	84	.564	14.66
2	83	.560	16.52
3	83	.574	15.52
4	77	.541	15.29
5	87	.580	15.91
6	87	.581	15.91
7	78	.545	14.27
8	--	--	--
9	94	.621	17.48
10	94	.609	21.54

Source: Nuclear and Alternate Fuels Division.

Real Escalation in Nuclear O&M Costs

The nuclear O&M costs are assumed to escalate in real terms by 1.5 percent per year.

Nuclear Plant Capital Additions and Escalation

A cost for post operational capital expenditures is also included. This cost (in 1988 dollars) is projected to be $40/kWe in the first year of the forecast period, fall by $2/Kwe per year for the first 5 years, and then escalate at 2.7 percent per year for the remaining period. The estimates assume a 1,100 MWe unit and the regional capacity factors for 1994.

Load Characteristics

In the Electricity Market Module utility load characteristics are represented by seasonal load profiles (load duration curves) for each of the Federal Regions. These profiles are used to optimize utility dispatched capacity addition decisions. The load duration curves currently being used were estimated using hourly load data for 1973 through 1982 (For more information see *Trends in Electric Utility Load Duration Curves*, DOE/EIA/19635-1 (December 1984). The shape of these curves is held constant over time. Analysis of hourly load data through 1982 indicated that, at the Federal Region level, load duration curve shapes did not change over the period 1973 through 1982.

While it is possible that individual utilities have altered the shapes of their load curves using demand-side-management programs, these effects are not seen at the Federal Region level.

Plant Retirement Assumptions

Announced utility requirements as reported on the EIA form 860 are included. In addition, it is assumed that small fossil steam plants (those under 100 megawatts) will be retired when they reach 45 years of age. Nuclear plants are assumed to retire after 40 years of service. Utilities are expected to maintain the performance of their larger fossil steam plants (which they have not reported plans to retire) by refurbishing them when their performance begins to degrade between their twenty-fifth and thirtieth years. The costs of this work are taken from the EIA report, *Estimating the Capital Costs of Life Extension for Fossil-Fuel Steam Plants.* The table below summarizes the amount of capacity projected to be retired by 2010.

Plant Type	Utility Planned Retirements	EIA Retirements	Total
Coal Steam	4,137	13,973	18,110
Gas Steam	1,629	1,568	3,197
Oil Steam	737	5,678	6,415
Gas\Oil Steam	5,963	9,940	15,903
Gas Combined Cycle	0	0	0
Oil Combined Cycle	0	0	0
Gas Turbine	112	0	112
Oil Turbine	1,236	0	1,236
Gas/Oil Turbine	611	0	611
Nuclear	0	5,509	5,509
Pumped Storage Hydro	0	0	0
Poundage Hydro/Other	153	0	153
All	14,547	36,668	51,247

Life Extension

Studies have indicated that, as a fossil-steam unit ages, its performance begins to degrade. This performance degradation is only slight through the first 25-30 years of the units life, but it becomes more significant as the unit continues to age. Barring efforts to maintain the performance of the unit, it eventually becomes uneconomical to continue operating it. Historically, most fossil steam units have been retired after 40-45 years of service.

However, many utilities are making efforts to extend the economic lives of their older fossil-steam units to 50-60 years. Initial estimates of the cost of life extension make it very attractive. And, in today's environment, with utilities trying to avoid constructing new generating units, it is unlikely that a utility will allow the performance of an existing unit to degrade if it can be economically maintained.

In the 1970 Clean Air Act, power plants constructed before August 1971 are not required to restrict emissions of air pollutants such as sulfur dioxide. However, if these older plants are "modified" or "reconstructed" in a major way, they are required to meet the stricter emissions standards applied to newer plants.

Until recently, no older plant had ever lost its exemption from complying with the stricter emissions standards. However, in October 1988 EPA ruled that Wisconsin Electric Power Company's (WEPCO) Port Washington coal units would have to comply with the new source emissions standards (RNSPS) after their planned renovation. Without a doubt this ruling sent a chill through the electric utility industry.

In the Port Washington case, EPA argued that the work planned by WEPCO (replacing steam drums, air heaters, and other major components) did not constitute routine maintenance to maintain the performance of the units and, thus, would subject the units to meeting the RNSPS standards. EPA argued that they could find no other example of a utility replacing a steam drum at an aging generating facility.

The WEPCO case is considered an isolated incident where a utility made a major modification (replaced a steam drum) that EPA could argue was not "normal" to maintain the performance of the unit. Other utilities will be careful to avoid performing work that would trigger EPA to make a similar decision. Another essential element of the WEPCO decision was whether the life extension expenditure would cause an increase in the annual emissions of the units, specifically whether there would be an emissions increase due to a physical or operational change. EPA rule 40 CFR Section 60.14 (e) states that "An increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on that facility, shall not by itself, be considered modifications under this part." Thus, if a unit has not fallen into disrepair and will not experience an increase in utilization as a direct result of capital investment, neither WEPCO nor the current regulations implementing the Clean Air Act would require a life-extended unit to comply with more stringent emissions standards. It is possible, even likely, that the environmental restrictions on older plants will be reviewed in the upcoming discussion of the proposed revisions to the Clean Air Act. The effect on utility life-extension plans of the need for fully life-extended plants to comply with stricter environmental standards should not be included in the base case, but in the Clean Air policy scenario.

The following describes the assumptions made to capture the cost and performance impacts of expected life extension work when EPA is not expected to require fully life-extended units to meet RNSPS environmental standards.

1. Only fossil steam plants with no reported retirement date are considered eligible for life extension.

2. Gas- and oil-fired steam plants are only eligible for life extension in DOE regions 1, 2, 6, and 9 or in Florida where they account for more than 10 percent of total generation. It is believed that regions that did not rely heavily on gas or oil generation would find other resource options more economically attractive.

3. Only plants with nameplate capacities greater than or equal to 100 MW were considered eligible for life extension. There are economies of scale in life extension work and many existing fossil-steam units with nameplate capacities below 100 MW are already over 30 years old.

4. All fossil steam units (with no reported retirement date) with nameplate capacities below 100 MW and gas- and oil-fired units not in the regions given above are retired after 45 years of service.

5. Two categories of life extension are established. Supercritical units and units currently operated at a capacity factor greater than 35 percent would be fully life-extended while the remaining units would be partially life-extended. Fully life extended units are assumed to perform as new units. On the other hand, partially life extended units will not be able to perform as new units and their maximum capacity factor will be limited to 40 percent after their 25 year. Many of the units currently being cycled could not be economically operated as baseload units and utilities are expected to spend less refurbishing them.

6. The costs of life-extending these units are to be taken from *Estimating the Capital Costs of Life Extension for Fossil-Fuel Steam Plants*, July 1988 (DOE/EIA-0509), Table 11. The costs of refurbishing the units to be fully life extended are the high costs shown in the table, while the low costs are used for the units to be partially life extended.

7. Life extended plants are to be refurbished over 5 years during planned outages after 25 years of service.

8. The refurbishment work to be performed is not expected to require the units to meet the Revised New Source Performance Standards (RNSPS). Costs would be much higher if RNSPS environmental standards must be met.

The table below summarizes the amount of capacity impacted by these assumptions.

Fossil-Fuel Life Extension and Retirement Capacity
(Gigawatts)

	Fully Retired	Partially Extended	Total Extended	Extended
	1990 - 2010[1]	1990 - 2010	1990 - 2010	1990 - 2010
Capacity	44.0	284.0	62.0	346.0

[1] Between 1990 and 2010 utilities have reported plans to retire 14.8 gigawatts of capacity. The data shown here include these planned retirements and additional retirements expected by EIA.

The table below gives the national costs per KW of life extension from *Estimating the Capital Costs of Life Extension for Fossil-Fuel Steam Plants*, July 1988 (DOE/EIA-0509), Table 11.

Capital Costs of Life Extension
(1987 dollars per Kilowatt)

Fuel	Partially Life Extended	Fully Life Extended
Coal	84	216
Gas	44	112
Oil	59	145

Capital Expenditures on Existing Plants

Average capital additions are presented by 12 plant types and 10 Federal Regions. The data represent average capital additions per megawatt for each plant type and region for 1980 through 1987 in 1982 dollars. The data come from the FERC form 1 and the EIA-412.

The plant types shown in Table C4 are:

CBCG	Gas Combined Cycle
CBCO	Oil Combined Cycle
HYD	Hydroelectric
HYDPMP	Hydroelectric Pumped Storage
STMC	Coal Steam
STMG	Gas Steam
STMO	Oil Steam
STMOG	Oil/Gas Steam
TURBG	Gas Turbine
TURBO	Oil Turbine
TURBOG	Oil/Gas Turbine

The 10 Federal Regions are shown in the columns. The mean is the average for each plant type; "N" is the number of observations.

Cumulative cash expenditure profiles for nuclear units are shown in Table C5. Values are in thousands of 1987 dollars. In a few instances, the values are for the total plant, whether 2 or 3 units. These plants and the recommended percentage split for units 1, 2 (and 3) are:

	Unit		
Plant	1	2	3
Watts Bar	55	45	
Salem	55	45	
Sequoia	55	45	
Browns Ferry	40	30	30

Table C4. Capital Additions By Plant Type

	Capital Additions, $ Per MW ($1982)									
	Region									
	1		2		3		4		5	
	Mean	**N**	**Mean**	**N**	**Mean**	**N**	**Mean**	**N**	**Mean**	**N**
Plant Type										
CBCG	.	.	.	.	.	.	1,437	7	1,513	1
CBCO	10,061	4	32	1	3,714	2	5,454	3	.	.
HYD	12,887	124	16,552	140	9,226	43	4,186	415	8,454	140
HYDPMP	913	19	3,721	4	986	19	1,789	28	119	5
STMC	7,142	9	12,288	53	11,763	224	6,482	362	7,183	431
STMG	3,419	2	7,147	6	14,255	1	1,270	23	365	16
STMO	7,834	55	4,302	38	1,219	18	2,206	45	2,471	11
STMOG	6,620	22	3,691	41	3,727	2	1,289	61	1,019	3
TURBG	.	.	851	45	1,461	19	7,542	34	1,597	68
TURBO	846	40	710	52	946	98	594	76	655	55
TURBOG	4,527	1	496	45	7,757	13	821	27	1,311	16

	6		7		8		9		10	
	Mean	**N**	**Mean**	**N**	**Mean**	**N**	**Mean**	**N**	**Mean**	**N**
Plant Type										
CBCG	561	11	14,453	1	.	.	2,559	17	5,646	1
CBCO	.	.	.	.	.	.	423	4	14,122	1
HYD	2,558	36	7,745	36	5,915	106	9,366	415	10,081	449
HYDPMP	717	3	262	8	5,342	5	3,267	9	.	.
STMC	14,469	60	5,079	105	8,384	117	6,066	19	2,529	11
STMG	1,545	310	940	42	1,712	12	4,489	86	16,627	6
STMO	.	.	821	2	.	.	10,612	41	487	3
STMOG	558	18	2,615	10	8	3	4,543	60	.	.
TURBG	2,317	22	452	20	514	12	1,638	68	7,578	10
TURBO	0	3	210	31	1,538	10	688	24	429	4
TURBOG	0	4	1,016	4	311	2	70	5	1,323	3

Table C5. Cumulative Cash Expenditures for Nuclear Plants

```
---------- PLANT=ANNA1 --------

   OBS     YEAR     CASHPR82

     1     1969        33924
     2     1970       149801
     3     1971       320076
     4     1972       570838
     5     1973       711311
     6     1974       792812
     7     1975       875942
     8     1976      1042782
     9     1977      1120774
    10     1978      1168619
```

```
---------- PLANT=ANNA2 --------

   OBS     YEAR     CASHPR82

    11     1970        18409
    12     1971        78913
    13     1972       161646
    14     1973       293437
    15     1974       338121
    16     1975       393186
    17     1976       445677
    18     1977       553898
    19     1978       654127
    20     1979       719649
    21     1980       700520
```

```
----------- PLANT=ARK1 --------

   OBS     YEAR     CASHPR82

    22     1967         1664
    23     1968        10530
    24     1969        40332
    25     1970        99742
    26     1971       303356
    27     1972       376684
    28     1973       418580
    29     1974       468893
```

```
----------- PLANT=ARK2 ------

   OBS     YEAR     CASHPR82

    30     1970         2193
    31     1971        25674
    32     1972        85814
    33     1973       238782
    34     1974       347201
    35     1975       452845
    36     1976       542854
    37     1977       633948
    38     1978       716353
    39     1979       766749
    40     1980       812295
```

```
---------- PLANT=ARNOLD -----

   OBS     YEAR     CASHPR82

    41     1968         3986
    42     1969        20253
    43     1970        82072
    44     1971       212192
    45     1972       393466
    46     1973       516118
    47     1974       537894
```

```
---------- PLANT=BEAVER1 -----

   OBS     YEAR     CASHPR82

    48     1969        32411
    49     1970       116721
    50     1971       317994
    51     1972       512400
    52     1973       623342
    53     1974       663184
    54     1975       845128
    55     1976       852338
    56     1977       883708
```

Table C5. Cumulative Cash Expenditures for Nuclear Plants (Continued)

```
--------- PLANT=BEAVER2 -----

     OBS     YEAR     CASHPR82

      57     1972         9416
      58     1973        66556
      59     1974       118393
      60     1975       166349
      61     1976       264739
      62     1977       430100
      63     1978       636927
      64     1979       812071
      65     1980       960238


--------- PLANT=BEAVER2 -------

     OBS     YEAR     CASHPR82

      66     1981     1101393
      67     1982     1265116
      68     1983     1510179
      69     1984     1779493
      70     1985     2252947
      71     1986     2981525
      72     1987     3144698


---------- PLANT=BRAID1 -------

     OBS     YEAR     CASHPR82

      73     1972         2354
      74     1973        22724
      75     1974        29724
      76     1975        42919
      77     1976       113145
      78     1977       245360
      79     1978       508729
      80     1979       682689
      81     1980       752331
      82     1981       841298
      83     1982       933848
      84     1983      1001811
      85     1984      1309953
      86     1985      1668772
      87     1986      2220838
```

```
--------- PLANT=BROWNS1 ----

     OBS     YEAR     CASHPR82

      89     1966        16145
      90     1967        86530
      91     1968       236951
      92     1969       509353
      93     1970       801760
      94     1971      1090026
      95     1972      1255427
      96     1973      1394262
      97     1974      1509654
      98     1975      1534464
      99     1976      1644681


---------- PLANT=BRUNS1 ----

     OBS     YEAR     CASHPR82

     100     1969            0
     101     1970        45608
     102     1971       124691
     103     1972       242926
     104     1973       376315
     105     1974       431605
     106     1975       483307
     107     1976       525730
     108     1977       539650


---------- PLANT=BRUNS2 ----

     OBS     YEAR     CASHPR82

     109     1969            0
     110     1970        96581
     111     1971       181471
     112     1972       420953
     113     1973       567318
     114     1974       665808
     115     1975       700648
```

Table C5. Cumulative Cash Expenditures for Nuclear Plants (Continued)

```
---------- PLANT=BYRON1 -------

   OBS    YEAR    CASHPR82

   116    1971         759
   117    1972        5573
   118    1973       23260
   119    1974       46354
   120    1975       98423
   121    1976      250982
   122    1977      433101
   123    1978      632532
   124    1979      805942
   125    1980      924864
   126    1981     1094721
   127    1982     1305798
   128    1983     1565809
   129    1984     1818025
   130    1985     1891608
```

```
---------- PLANT=BYRON2 -------

   OBS    YEAR    CASHPR82

   131    1971         472
   132    1972        1292
   133    1973        2906
   134    1974       10194
   135    1975       20835
   136    1976      108966
   137    1977      220335
   138    1978      332082
   139    1979      438245
   140    1980      510827
   141    1981      575769
   142    1982      653704
   143    1983      730130
   144    1984      828936
   145    1985     1256105
   146    1986     1543796
   147    1987     1626326
```

```
--------- PLANT=CALHOUN -------

   OBS    YEAR    CASHPR82

   148    1967           0
   149    1968       71065
   150    1969      146810
   151    1970      237593
   152    1971      290523
   153    1972      351167
   154    1973      390795
```

```
--------- PLANT=CALLWAY ----

   OBS    YEAR    CASHPR82

   155    1974       19687
   156    1975       37004
   157    1976      128392
   158    1977      279028
   159    1978      545738
   160    1979      803075
   161    1980     1052802
   162    1981     1322647
   163    1982     1595266
   164    1983     1906946
   165    1984     2282398
```

```
--------- PLANT=CALVER1 ----

   OBS    YEAR    CASHPR82

   166    1967           0
   167    1968       60122
   168    1969      123740
   169    1970      246355
   170    1971      482648
   171    1972      627909
   172    1973      716094
   173    1974      827797
   174    1975      858099
```

```
--------- PLANT=CALVER2 ----

   OBS    YEAR    CASHPR82

   175    1967           0
   176    1968           0
   177    1969       25613
   178    1970      103887
   179    1971      216923
   180    1972      362134
   181    1973      464564
   182    1974      489940
   183    1975      519328
   184    1976      573362
   185    1977      574989
```

Table C5. Cumulative Cash Expenditures for Nuclear Plants (Continued)

```
--------- PLANT=CATAWB1 -------
   OBS      YEAR      CASHPR82

   186      1972          1660
   187      1973          6293
   188      1974         25833
   189      1975         65008
   190      1976        159783
   191      1977        290229
   192      1978        470756
   193      1979        628173
   194      1980        813092
   195      1981        886150
   196      1982       1062685
   197      1983       1210673
   198      1984       1304038
   199      1985       1558099


--------- PLANT=CATAWB2 -------

   OBS      YEAR      CASHPR82

   200      1972          1660
   201      1973          6293
   202      1974         25833
   203      1975         65008
   204      1976        159783
   205      1977        257326
   206      1978        365034
   207      1979        539541
   208      1980        576436
   209      1981        622902
   210      1982        761183
   211      1983        876038
   212      1984       1055945
   213      1985       1103028
   214      1986       1266456

--------- PLANT=CLINTON1 ------

   OBS      YEAR      CASHPR82

   215      1973         12422
   216      1974         29432
   217      1975        169287
   218      1976        235129
   219      1977        482065
   220      1978        643778
   221      1979        895785
   222      1980       1125198
   223      1981       1406805
   224      1982       1669573
   225      1983       1907364
   226      1984       2331530
   227      1985       3068439
   228      1986       3260989
```

```
---------- PLANT=COOK1 ------
   OBS      YEAR      CASHPR82

   230      1968             0
   231      1969         56880
   232      1970        342101
   233      1971        499155
   234      1972        843563
   235      1973        749231
   236      1974        839246
   237      1975        978602


---------- PLANT=COOPER -----

   OBS      YEAR      CASHPR82

   238      1967         13231
   239      1968         85984
   240      1969        185234
   241      1970        322951
   242      1971        512714
   243      1972        624307
   244      1973        724833
   245      1974        791487


--------- PLANT=CRYSTAL -----

   OBS      YEAR      CASHPR82

   246      1967             0
   247      1968         53362
   248      1969         66310
   249      1970        134426
   250      1971        301826
   251      1972        397340
   252      1973        540975
   253      1974        579083
   254      1975        588223
   255      1976        615931
   256      1977        712104

---------- PLANT=DAVIS1 -----

   OBS      YEAR      CASHPR82

   257      1968          1606
   258      1969          7862
   259      1970         49623
   260      1971        138816
   261      1972        297630
   262      1973        525023
   263      1974        657432
   264      1975        766698
   265      1976        884782
   266      1977       1020691
```

Table C5. Cumulative Cash Expenditures for Nuclear Plants (Continued)

```
--------- PLANT=DIABLO1 -------

  OBS      YEAR      CASHPR82

  267      1967         13208
  268      1968         46771
  269      1969        189734
  270      1970        351713
  271      1971        481897
  272      1972        614416
  273      1973        725729
  274      1974        830193
  275      1975        939302
  276      1976       1010268
  277      1977       1063558
  278      1978       1105402
  279      1979       1193821
  280      1980       1212566
  281      1981       1439900
  282      1982       1664469
  283      1983       2007980
  284      1984       2754493
  285      1985       2817185


--------- PLANT=DIABLO2 -------

  OBS      YEAR      CASHPR82

  286      1968             0
  287      1969         25679
  288      1970         58530
  289      1971        127762
  290      1972        291400
  291      1973        428562
  292      1974        520539
  293      1975        594505
  294      1976        714299
  295      1977        737836
  296      1978        804119
  297      1979        864382
  298      1980        875804
  299      1981       1010802
  300      1982       1093290
  301      1983       1249055
  302      1984       1419911
  303      1985       1982556
  304      1986       2083439
```

```
--------- PLANT=FARLEY1 ----

  OBS      YEAR      CASHPR82

  305      1969          7363
  306      1970         25079
  307      1971        119243
  308      1972        289715
  309      1973        595531
  310      1974        760426
  311      1975        874450
  312      1976       1020073
  313      1977       1098921


--------- PLANT=FARLEY2 ----

  OBS      YEAR      CASHPR82

  314      1969             0
  315      1970            81
  316      1971          2761
  317      1972         33192
  318      1973        120883
  319      1974        287021
  320      1975        463187
  321      1976        488658
  322      1977        528232
  323      1978        654753
  324      1979        720706
  325      1980        834997
  326      1981        922644
```

Table C5. Cumulative Cash Expenditures for Nuclear Plants (Continued)

```
---------- PLANT=FERMI2 -------

   OBS     YEAR     CASHPR82

   327     1969        10503
   328     1970        65791
   329     1971       193269
   330     1972       312198
   331     1973       445193
   332     1974       612699
   333     1975       674546
   334     1976       718762
   335     1977       752236
   336     1978      1038320
   337     1979      1177936
   338     1980      1218124
   339     1981      1478441
   340     1982      2046245
   341     1983      2425949
   342     1984      2790394
   343     1985      3006052
   344     1986      3077698
```

```
---------- PLANT=GRAND1 -------

   OBS     YEAR     CASHPR82

   346     1972         8347
   347     1973        34999
   348     1974        82122
   349     1975       132977
   350     1976       596322
   351     1977       829082
   352     1978      1104859
   353     1979      1398932
   354     1980      1676861
   355     1981      2023789
   356     1982      2352617
   357     1983      2538442
   358     1984      2543669
   359     1985      2609728
```

```
--------- PLANT=HARRIS1 ----

   OBS     YEAR     CASHPR82

   360     1971          358
   361     1972        13410
   362     1973        42749
   363     1974       212264
   364     1975       283990
   365     1976       315238
   366     1977       376840
   367     1978       557761
   368     1979       834893
   369     1980      1114259
   370     1981      1329877
   371     1982      1356228
   372     1983      1620973
   373     1984      2024206
   374     1985      2636289
   375     1986      2959146
```

```
---------- PLANT=HATCH1 ----

   OBS     YEAR     CASHPR82

   377     1968            0
   378     1969        62360
   379     1970       151794
   380     1971       374711
   381     1972       512535
   382     1973       607705
   383     1974       699366
   384     1975       714484
```

```
---------- PLANT=HATCH2 ----

   OBS     YEAR     CASHPR82

   385     1970          807
   386     1971         7209
   387     1972        58250
   388     1973       104657
   389     1974       266713
   390     1975       391863
   391     1976       470328
   392     1977       568634
   393     1978       608884
   394     1979       693056
```

Table C5. Cumulative Cash Expenditures for Nuclear Plants (Continued)

```
---------- PLANT=HOPE1 --------

  OBS     YEAR     CASHPR82

  395     1970        23240
  396     1971        42823
  397     1972        69805
  398     1973        97136
  399     1974       135279
  400     1975       188056
  401     1976       296716
  402     1977       475406
  403     1978       685721
  404     1979       912805
  405     1980      1124026
  406     1981      1273756
  407     1982      1945256
  408     1983      2375050
  409     1984      2800462
  410     1985      3358833
  411     1986      3683691
```

```
--------- PLANT=INDIAN3 -------

  OBS     YEAR     CASHPR82

  412     1967        35122
  413     1968        90847
  414     1969       149249
  415     1970       290245
  416     1971       341594
  417     1972       325438
  418     1973       529351
  419     1974       573096
  420     1975       643120
  421     1976       645443
```

```
--------- PLANT=KEWAUNE -------

  OBS     YEAR     CASHPR82

  422     1967         8162
  423     1968        49261
  424     1969        93399
  425     1970       165964
  426     1971       277627
  427     1972       341041
  428     1973       402062
  429     1974       420274
```

```
--------- PLANT=LASALL1 ----

  OBS     YEAR     CASHPR82

  430     1970        12484
  431     1971        38569
  432     1972        56593
  433     1973        96017
  434     1974       185924
  435     1975       284395
  436     1976       477208
  437     1977       611186
  438     1978       814344
  439     1979       973359
  440     1980      1139553
  441     1981      1299859
  442     1982      1441325
```

```
--------- PLANT=LASALL2 ----

  OBS     YEAR     CASHPR82

  443     1970          110
  444     1971         1152
  445     1972         5324
  446     1973        29223
  447     1974       106943
  448     1975       201074
  449     1976       313013
  450     1977       455934
  451     1978       507318
  452     1979       566248
  453     1980       635339
  454     1981       744653
  455     1982       842245
  456     1983       942595
```

Table C5. Cumulative Cash Expenditures for Nuclear Plants (Continued)

```
--------- PLANT=LIMERK1 -------

     OBS     YEAR     CASHPR82

     457     1970         8412
     458     1971        48364
     459     1972       123441
     460     1973       225319
     461     1974       395485
     462     1975       525808
     463     1976       747399
     464     1977       829345
     465     1978       978580
     466     1979      1087860
     467     1980      1258472
     468     1981      1537149
     469     1982      1594702
     470     1983      1898763
     471     1984      2634708
     472     1985      2990034
```

```
---------- PLANT=LUCIE1 -------

     OBS     YEAR     CASHPR82

     473     1969        51875
     474     1970       119457
     475     1971       235583
     476     1972       365764
     477     1973       471275
     478     1974       626574
     479     1975       782058
     480     1976       849302
```

```
---------- PLANT=LUCIE2 -------

     OBS     YEAR     CASHPR82

     481     1972            0
     482     1973        14308
     483     1974        48447
     484     1975       103415
     485     1976       190502
     486     1977       309004
     487     1978       445125
     488     1979       599898
     489     1980       780557
     490     1981      1068484
     491     1982      1135607
     492     1983      1418497
```

```
--------- PLANT=MCQUIR1 ----

     OBS     YEAR     CASHPR82

     493     1970         3531
     494     1971        10856
     495     1972        48455
     496     1973       125191
     497     1974       283163
     498     1975       387148
     499     1976       494664
     500     1977       668000
     501     1978       724423
     502     1979       785890
     503     1980       927861
     504     1981       951603
     505     1982       975603
```

```
--------- PLANT=MCQUIR2 ----

     OBS     YEAR     CASHPR82

     506     1970         3531
     507     1971        10856
     508     1972        48455
     509     1973       125191
     510     1974       283163
     511     1975       387317
     512     1976       494663
     513     1977       502221
     514     1978       582686
     515     1979       658624
     516     1980       680955
     517     1981       736920
     518     1982       864293
     519     1983       953535
```

```
--------- PLANT=MILSTN2 ----

     OBS     YEAR     CASHPR82

     521     1968          938
     522     1969        18608
     523     1970        88394
     524     1971       193597
     525     1972       339129
     526     1973       517182
     527     1974       622898
     528     1975       703265
```

Table C5. Cumulative Cash Expenditures for Nuclear Plants (Continued)

```
--------- PLANT=MILSTN3 -------

   OBS     YEAR     CASHPR82

   529     1974       113034
   530     1975       380781
   531     1976       540839
   532     1977       592527
   533     1978       675446
   534     1979       771063
   535     1980       900343
   536     1981      1097114
   537     1982      1836032
   538     1983      2235063
   539     1984      2643914
   540     1985      2756304
   541     1986      3003760
```

```
---------- PLANT=NINE2 --------

   OBS     YEAR     CASHPR82

   542     1972        32368
   543     1973        96477
   544     1974        96831
   545     1975       134855
   546     1976       301341
   547     1977       509501
   548     1978       728372
   549     1979       922786
   550     1980      1081431
   551     1981      1348362
   552     1982      1759733
   553     1983      2257105
   554     1984      2873180
   555     1985      3479345
   556     1986      4306597
```

```
--------- PLANT=PALISDE -------

   OBS     YEAR     CASHPR82

   558     1966        14703
   559     1967        63487
   560     1968       195734
   561     1969       281605
   562     1970       310894
   563     1971       325188
```

```
---------- PLANT=PALO1 ------

   OBS     YEAR     CASHPR82

   564     1974        38072
   565     1975        95393
   566     1976       205599
   567     1977       458968
   568     1978       855667
   569     1979      1333157
   570     1980      1446909
   571     1981      1742817
   572     1982      2046131
   573     1983      2251559
   574     1984      2827533
   575     1985      3144500
```

```
---------- PLANT=PALO2 ------

   OBS     YEAR     CASHPR82

   576     1974        10758
   577     1975         7336
   578     1976        14349
   579     1977        79886
   580     1978       263955
   581     1979       420511
   582     1980       762862
   583     1981       903788
   584     1982      1115856
   585     1983      1229170
   586     1984      1431097
   587     1985      1685225
   588     1986      1779570
```

```
---------- PLANT=PALO3 ------

   OBS     YEAR     CASHPR82

   589     1974         8691
   590     1975         5447
   591     1976        10702
   592     1977        21737
   593     1978        33587
   594     1979       116572
   595     1980       452440
   596     1981       529341
   597     1982       824733
   598     1983       909706
   599     1984      1020403
   600     1985      1188089
   601     1986      1702557
   602     1987      1833934
```

Table C5. Cumulative Cash Expenditures for Nuclear Plants (Continued)

```
---------- PLANT=PEACH2 -------

   OBS     YEAR    CASHPR82

   603     1968      153205
   604     1969      228451
   605     1970      470841
   606     1971      599383
   607     1972      699863
   608     1973      993835
   609     1974     1065370


---------- PLANT=PEACH3 -------

   OBS     YEAR    CASHPR82

   610     1968       29601
   611     1969       53144
   612     1970      160512
   613     1971      268279
   614     1972      482762
   615     1973      419675
   616     1974      421094


---------- PLANT=PERRY1 -------

   OBS     YEAR    CASHPR82

   617     1973       11096
   618     1974       25781
   619     1975       75626
   620     1976      173779
   621     1977      333742
   622     1978      414203
   623     1979      462799
   624     1980      674793
   625     1981     1148280
   626     1982     1445114
   627     1983     1804012
   628     1984     2360975
   629     1985     2801589
```

```
---------- PLANT=RANCHO -----

   OBS     YEAR    CASHPR82

   632     1967        3585
   633     1968        8541
   634     1969       68728
   635     1970      145429
   636     1971      318661
   637     1972      506453
   638     1973      597679
   639     1974      639994
   640     1975      657901


---------- PLANT=RIVER1 -----

   OBS     YEAR    CASHPR82

   641     1972       19496
   642     1973       48506
   643     1974      105856
   644     1975      179952
   645     1976      347917
   646     1977      499919
   647     1978      688582
   648     1979      831015
   649     1980     1309809
   650     1981     1414108
   651     1982     1785988
   652     1983     2264998
   653     1984     2760894
   654     1985     3073347


---------- PLANT=SALEM1 -----

   OBS     YEAR    CASHPR82

   656     1966           0
   657     1967       28219
   658     1968      121068
   659     1969      390229
   660     1970      608756
   661     1971      926883
   662     1972     1161816
   663     1973     1419865
   664     1974     1640847
   665     1975     1829278
   666     1976     2005271
   667     1977     2165197
   668     1978     2342997
   669     1979     2441795
   670     1980     2498875
   671     1981     2498875
```

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Table C5. Cumulative Cash Expenditures for Nuclear Plants (Continued)

```
--------- PLANT=SEABROOK ------

 OBS    YEAR    CASHPR82

 672    1973       40828
 673    1974       93674
 674    1975      185954
 675    1976      399143
 676    1977      781342
 677    1978     1363770
 678    1979     1835250
 679    1980     2302922
 680    1981     2234932
 681    1982     2626910
 682    1983     3172276
 683    1984     3400915
 684    1985     3841192
 685    1986     4057320
```

```
--------- PLANT=SEQUHY1 -------

 OBS    YEAR    CASHPR82

 686    1968        3405
 687    1969       35566
 688    1970      112090
 689    1971      319276
 690    1972      655941
 691    1973      813557
 692    1974      922850
 693    1975     1086502
 694    1976     1255596
 695    1977     1421785
 696    1978     1535824
 697    1979     1750802
 698    1980     1886688
 699    1981     2040382
 700    1982     2102380
 701    1983     2130922
```

```
--------- PLANT=SHORHAM -------

 OBS    YEAR    CASHPR82

 702    1967           0
 703    1968        8880
 704    1969       25005
 705    1970       69594
 706    1971      136244
 707    1972      167224
 708    1973      253414
 709    1974      455555
 710    1975      647545
 711    1976      853337
 712    1977     1067025
 713    1978     1286949
```

```
--------- PLANT=SHORHAM -----

 OBS    YEAR    CASHPR82

 714    1979    1560367
 715    1980    1815750
 716    1981    2093305
 717    1982    2496522
 718    1983    2760603
 719    1984    3023590
 720    1985    3109526
```

```
--------- PLANT=SONFRE2 -----

 OBS    YEAR    CASHPR82

 721    1970           0
 722    1971       29453
 723    1972       57629
 724    1973       76385
 725    1974      148342
 726    1975      338474
 727    1976      579569
 728    1977      859930
 729    1978     1083454
 730    1979     1456887
 731    1980     1917791
 732    1981     2168481
 733    1982     2174468
 734    1983     2511826
```

```
--------- PLANT=SONFRE3 -----

 OBS    YEAR    CASHPR82

 735    1970           0
 736    1971       24162
 737    1972       45803
 738    1973       76766
 739    1974      137318
 740    1975      279948
 741    1976      475760
 742    1977      705145
 743    1978      888030
 744    1979      980042
 745    1980      930154
 746    1981     1221845
 747    1982     1457616
 748    1983     1498485
 749    1984     1562638
```

Table C5. Cumulative Cash Expenditures for Nuclear Plants (Continued)

```
--------- PLANT=SUMNER1 -------

   OBS     YEAR     CASHPR82

   750     1971         5659
   751     1972        17851
   752     1973        53552
   753     1974       181010
   754     1975       268426
   755     1976       473104
   756     1977       548520
   757     1978       803114
   758     1979       911495
   759     1980       979975
   760     1981      1097975
   761     1982      1278087
   762     1983      1282782
```

```
---------- PLANT=SURRY1 -------

   OBS     YEAR     CASHPR82

   763     1967       35778
   764     1968      111993
   765     1969      311010
   766     1970      456266
   767     1971      510172
   768     1972      576637
```

```
---------- PLANT=SURRY2 -------

   OBS     YEAR     CASHPR82

   769     1967       12604
   770     1968       44731
   771     1969      101629
   772     1970      216985
   773     1971      263837
   774     1972      323751
   775     1973      328395
```

```
--------- PLANT=SUSQUA1 -------

   OBS     YEAR     CASHPR82

   776     1971         9484
   777     1972        16935
   778     1973        33343
   779     1974       181488
   780     1975       330007
   781     1976       461048
   782     1977       800012
   783     1978      1041832
   784     1979      1257318
   785     1980      1582406
```

```
--------- PLANT=SUSQUA1 ----

   OBS     YEAR     CASHPR82

   786     1981      1767203
   787     1982      2031498
   788     1983      1993771
```

```
--------- PLANT=SUSQUA2 ----

   OBS     YEAR     CASHPR82

   789     1972        17132
   790     1973        33289
   791     1974         8801
   792     1975        89888
   793     1976       218431
   794     1977       298499
   795     1978       433901
   796     1979       504984
   797     1980       593086
   798     1981       722531
   799     1982       789442
   800     1983      1659199
   801     1984      1674050
   802     1985      1788565
```

```
----------- PLANT=TMI1 -----

   OBS     YEAR     CASHPR82

   803     1967         6726
   804     1968        48293
   805     1969       147924
   806     1970       376335
   807     1971       501952
   808     1972       619770
   809     1973       727724
   810     1974       755878
   811     1975       757256
```

```
----------- PLANT=TMI2 -----

   OBS     YEAR     CASHPR82

   812     1969        85785
   813     1970       124082
   814     1971       210723
   815     1972       331686
   816     1973       489169
   817     1974       596559
   818     1975       701603
   819     1976       805616
   820     1977       899111
   821     1978       966834
```

Table C5. Cumulative Cash Expenditures for Nuclear Plants (Continued)

---------- PLANT=TROJAN -------

OBS	YEAR	CASHPR82
822	1969	21198
823	1970	43436
824	1971	119690
825	1972	342467
826	1973	535590
827	1974	659532
828	1975	791264
829	1976	860041

--------- PLANT=WATERFR -------

OBS	YEAR	CASHPR82
830	1970	889
831	1971	6806
832	1972	49620
833	1973	95910
834	1974	201157
835	1975	256702
836	1976	370956
837	1977	566598
838	1978	833343
839	1979	1067467
840	1980	1233849
841	1981	1462702
842	1982	1846476
843	1983	2203988
844	1984	2355332
845	1985	2481863

--------- PLANT=WATTSBAR ------

OBS	YEAR	CASHPR82
846	1970	1884
847	1971	13739
848	1972	33743
849	1973	155787
850	1974	435679
851	1975	733898
852	1976	943845
853	1977	1162692
854	1978	1371119
855	1979	1520792
856	1980	1669515
857	1981	1800022
858	1982	2177043
859	1983	2480601
860	1984	2708403
861	1985	2986751
862	1986	3478218
863	1987	3677098

--------- PLANT=WATTSBAR ---

OBS	YEAR	CASHPR82
864	1988	3716094

---------- PLANT=WOLF1 -----

OBS	YEAR	CASHPR82
865	1974	23532
866	1975	42914
867	1976	75541
868	1977	185012
869	1978	376775
870	1979	657667
871	1980	895711
872	1981	1014865
873	1982	1237531
874	1983	1495265
875	1984	2018840
876	1985	2130092

---------- PLANT=WPPSS2 ----

OBS	YEAR	CASHPR82
877	1971	6998
878	1972	21195
879	1973	155955
880	1974	294714
881	1975	554385
882	1976	718264
883	1977	931458
884	1978	1492439
885	1979	1689838
886	1980	1778898
887	1981	2018058
888	1982	2390823
889	1983	2832409
890	1984	3011540

---------- PLANT=ZION1 -----

OBS	YEAR	CASHPR82
891	1967	12885
892	1968	59546
893	1969	162516
894	1970	329257
895	1971	472059
896	1972	550705
897	1973	577033

Table C5. Cumulative Cash Expenditures for Nuclear Plants (Continued)

```
---------- PLANT=ZION2 --------

     OBS     YEAR     CASHPR82

     898     1967            0
     899     1968        17657
     900     1969        78216
     901     1970       174939
     902     1971       364686
     903     1972       471918
     904     1973       542760
     905     1974       565119
```

Decommissioning Costs for Nuclear Plants

The unit-specific decommissioning cost estimates (Table C6) are obtained from the 1985 issue of *Commercial Nuclear Power: Prospects for the United States and the World.* These estimates have been averaged by Federal Region to facilitate their use in the model (Table C7).

Table C6. Estimated Decommissioning Costs For Selected U.S. Nuclear Power Plants

State of Jurisdiction	Plant, Unit	Reactor[a]		Utility's Estimated Date of Decommissioning	Utility's Estimated Costs	
		Type	Capacity (Net MWe)		Total (million 1983 dollars)	Per Kilowatt (1983 dollars)
Alabama	Farley 1	PWR	829	2012	40.96	49.41
	Farley 2	PWR	829	2012	40.02	48.28
Arkansas	Arkansas Nuclear One 1	PWR	850	2009-2014	29.43	34.62
	Arkansas Nuclear One 2	PWR	912	2011-2016	27.04	29.65
California	San Onofre 1	PWR	436	1997	110.25	252.86
	San Onofre 2	PWR	1,070	2015	120.99	113.07
	San Onofre 3	PWR	1,080	2015	137.02	126.87
	Diablo Canyon 1	PWR	1,084	2015	104.81	95.72
	Diablo Canyon 2	PWR	1,084	2015	104.81	95.72
	Humboldt Bay 3	BWR	65	[b]1984-2014	52.15	802.24
Connecticut	Millstone 1	BWR	660	2006	93.80	142.12
	Millstone 2	PWR	870	2010	94.70	108.85
Florida	Turkey Point 3	PWR	693	2007	80.28	115.85
	Turkey Point 4	PWR	693	2007	58.57	84.52
	St. Lucie 1	PWR	830	2010	86.62	104.36
	St. Lucie 2	PWR	804	2023	74.52	92.64
	Crystal River 3	PWR	825	2008	84.44	102.35
Iowa	Quad Cities 1[c]	BWR	789	2007	NA	NA
	Quad Cities 2[c]	BWR	789	2007	NA	NA
	Duane Arnold 1	BWR	538	2004	NA	NA
	Cooper 1[d]	BWR	778	2004	NA	NA
Kansas	Wolf Creek	PWR	1,150	NA	NA	NA
Maryland	Calvert Cliffs 1	PWR	945	2009	46.88	55.48
	Calvert Cliffs 2	PWR	945	2009	46.88	55.48
Michigan	Enrico Fermi 1	PWR	61	NA	12.44	203.91
	Enrico Fermi 2	BWR	1,093	NA	121.34	111.02
	Big Rock 1	PWR	805	2007	97.06	120.57
	Palisades 1	PWR	805	2007	97.06	120.57

See footnotes at end of table.

Table C6. Estimated Decommissioning Costs For Selected U.S. Nuclear Power Plants (Continued)

State of Jurisdiction	Plant, Unit	Reactor[a] Type	Reactor[a] Capacity (Net MWe)	Utility's Estimated Date of Decommissioning	Utility's Estimated Costs Total (million 1983 dollars)	Utility's Estimated Costs Per Kilowatt (1983 dollars)
New Hampshire	Seabrook 1	PWR	1,198	NA	137.34	114.64
	Seabrook 2	PWR	1,198	NA	137.34	114.64
New Jersey	Salem 1[a]	PWR	1,090	2008	43.00	39.45
New York	Ginna 1	PWR	470	NA	52.92	112.60
	Indian Point 2	PWR	873	NA	72.73	86.31
	Nine Mile Point 1	BWR	620	NA	69.61	112.28
North Carolina	Brunswick 1	BWR	821	2000	61.59	75.02
	Brunswick 2	BWR	821	2000	81.99	99.87
	McGuire 1	PWR	1,180	2010	55.11	46.70
	McGuire 2	PWR	1,180	2013	55.11	46.70
Pennsylvania	Beaver Valley 1	PWR	835	2010	64.60	77.36
	Peach Bottom 2[a]	BWR	1,065	2008	58.10	54.55
	Peach Bottom 3[a]	BWR	1,065	2008	58.10	54.55
	Susquehanna 1	BWR	1,065	2023	86.50	81.22
	Three Mile Island 1[a]	PWR	819	2011	37.70	46.03
South Carolina	Oconee 1	PWR	887	2003	60.07	67.72
	Oconee 2	PWR	887	2003	60.07	67.72
	Oconee 3	PWR	887	2003	60.07	67.72
	Robinson 2	PWR	700	1997	53.63	76.61
	V.C. Summer 1	PWR	900	2013	50.36	55.96
Texas	Comanche Peak 1	PWR	1,150	2115	104.00	90.43
	Comanche Peak 1	PWR	1,150	2115	104.00	90.43
	Palo Verde 1	PWR	1,304	2114	83.20	63.80
	Palo Verde 2	PWR	1,304	2115	83.20	63.80
	Palo Verde 3	PWR	1,304	2116	83.20	63.80
	River Bend 1	BWR	934	2116	NA	NA
	South Texas 1	PWR	1,250	2117	NA	NA
	South Texas 2	PWR	1,250	2119	NA	NA
Maryland	Calvert Cliffs 1	PWR	945	2009	46.88	55.48
	Calvert Cliffs 2	PWR	945	2009	46.88	55.48
Michigan	Enrico Fermi 1	FBR	61	NA	12.44	203.91
	Enrico Fermi 2	BWR	1,093	NA	121.34	111.02
	Big Rock 1	PWR	805	2007	97.06	120.57
	Palisades 1	PWR	805	2007	97.06	120.57

See footnotes at end of table.

Table C6. Estimated Decommissioning Costs For Selected U.S. Nuclear Power Plants (Continued)

State of Jurisdiction	Plant, Unit	Reactor[a]		Utility's Estimated Date of Decommissioning	Utility's Estimated Costs	
		Type	Capacity (Net MWe)		Total (million 1983 dollars)	Per Kilowatt (1983 dollars)
Virginia	North Anna 1	PWR	907	2010	[f]118.38	65.26
	North Anna 2	PWR	907	2010		65.26
	Salem 1	PWR	1,090	2008	NA	NA
	Salem 2	PWR	1,115	2008	NA	NA
	Peach Bottom 2	BWR	1,065	2008	NA	NA
	Peach Bottom 3	BWR	1,065	2008	NA	NA
	Surry 1	PWR	788	2003	[f]112.41	71.33
	Surry 2	PWR	788	2003		71.33
Wisconsin	Kewaunee	PWR	535	2008	71.35	133.37
	Point Beach 1	PWR	497	2007	52.46	105.56
	Point Beach 2	PWR	497	2008	52.46	105.56

---

[a] Reactor Type: BWR, boiling-water reactor; FBR, fast breeder reactor; PWR, pressurized-water reactor.

[b] Safe storage to begin in 1984, dismantlement in 2014.

[c] Plant is located in Illinois, but one-fourth ownership interest in is Iowa.

[d] Plant is located in Nebraska, but one-half ownership interest is in Iowa.

[e] Because of joint ownership or interstate electricity sales, the reported decommissioning cost may not reflect 100 percent of the estimated cost.

[f] Combined cost for both units at the site.

[g] WA = not available.

[h] Source: R.A. Cantor, *Nuclear Power Decommissioning: Analysis of Regulatory Environments*, TM-244/85 (Oak Ridge National Laboratory, Oak Ridge, Tennessee, 1985).

Table C7. Average Estimated Decommissioning Costs[1] for Selected U.S. Nuclear Power Generating Units[2] by Federal Region

Region	Sample Size	Mean Value
1	4	112
2	3	63
3	8	57
4	16	60
5	6	71
6	7	71
7	0	--
8	0	--
9	6	101
10	0	--
All Regions	50	72

[1] Total costs, in millions of 1982 dollars.

[2] Based on Table 12, pages 35-37, *Commercial Nuclear Power: Prospects for the United States and the World* (DOE/EIA)-0438(85)). The numbers in Table 12, expressed in 1983 dollars, were deflated by 1.038 to derive costs in 1982 dollars. Plants from Table 12 are not included in the average cost calculation when costs are not available or may not reflect 100 percent of the plant. Fermi 1, a fast breeder reactor, is not included.

Nuclear Fuel Costs

The following table presents the average core-resident fuel costs in 1988 mills per kilowatt-hour.

Year	Mills/kWh(e)
1988	7.5
1989	7.0
1990	6.6
1991	6.2
1992	6.0
1993	5.8
1994	5.7
1995	5.6
1996	5.5
1997	5.5
1998	5.4
1999	5.4
2000	5.3
2001	5.3
2002	5.2
2003	5.2
2004	5.1
2005	5.1
2006	5.0
2007	5.0
2008	5.0
2009	4.9
2010	4.9

Source: Nuclear and Alternate Fuels Division.

New Plant Construction for Current Technologies

Except for units currently planned or under construction, no new nuclear or hydroelectric generating capacity is assumed through 2010.

Licensing and construction periods are assumed to be 8 years for coal-fired units, 5 years for combined cycle units, and 3 years for combustion turbines.

Table C8 presents estimates for construction costs, including a 15 percent contingency, for new generating units. These costs represent "overnight" costs, that is, they do not include interest charges. Interest charges are added by the model and depend on construction profiles, costs of capital, and regulatory policy (AFUDC vs. CWIP). Costs for coal steam units are provided by the CONCEPT5 model, which contains data from actual construction projects. These costs vary by region to account for differences in labor costs and plant design due to coal type. Costs for other fossil-fired units and hydroelectric units were derived using the EPRI, "Technical Assessment Guide 1986."

Table C8. Estimated Overnight Construction Costs For Current Technologies, Midwest Region (1988 Dollars Per Kilowatt)

Type of Generating Capacity	Cost
Oil-Fired Steam	819
Gas-Fired Steam	721
Coal-Fired Steam with Flue Gas Desulfurization (FGD)	
Bituminous (Low-Sulfur)	1,253
Bituminous (Medium-Sulfur)	1,279
Bituminous (High-Sulfur)	1,322
Subbituminous (Low-Sulfur)	1,292
Subbituminous (Medium-Sulfur)	1,334
Lignite (Low-Sulfur)	1,299
Lignite (Medium-Sulfur)	1,253
Combined Cycle	516
Combustion Turbine (Gas)	299
Combustion Turbine (Distillate)	299
Pondage Hydroelectric	932
Pumped Storage	1,057

Note: The costs for low- and medium-sulfur lignite-fired plants are from Federal Regions 8 and 6, respectively, because region 5 does not use lignite.

Sources: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels. Coal-Fired Steam units with FGD estimated from Oak Ridge National Laboratory CONCEPT-5 model. All other types of generating capacity estimated from EPRI *Technical Assessment Guide 1986* and Oak Ridge National Laboratory CONCEPT-5 model.

New Generating Technologies

Although they are not currently available commercially, there are several promising coal-fired and combined-cycle technologies being designed and tested for market penetration well before 2010. These new technologies offer significant improvements in performance and reduced environmental impacts when compared to existing systems.

Because it is not possible to represent all of the emerging technologies in the EIA modeling system, expert judgement has been used to develop cost and performance profiles for an advanced coal technology and an advanced combined-cycle technology. The model will be allowed to choose these technologies beginning in 2005. Table C9 gives the heat rates and overnight construction costs, including a 15 percent contingency used to represent the advanced technologies. When the model chooses these advanced technologies, expert judgement will be used to determine the actual technologies selected (such as atmospheric fluidized bed, pressurized fluidized bed, or integrated coal gasification combined-cycle).

Table C9. Generic Technology Profiles

	Advanced Coal	Advanced Combined-Cycle
Overnight Cost with 15% Contingency (1988 dollars per kilowatt)	1,250	516
Heat Rate (Btu per kilowatthour)	7,940	7,293

Sources: The costs and performance profiles for these generic technologies were derived with information from the Office of Fossil Energy (contained in the October 25, 1989 memorandum from Richard Dye titled Cost and Performance of Advanced Coal Technology) for the advanced coal plants, and Oak Ridge National Laboratory (*Energy Economic Data Base (EEDB) Program Phase IX Update (1987) Report AECC5-A Supplement*, ORNL/Sub/87-8600 4/5, May 1989) for the advanced combined-cycle plant.

Methodology for Projecting U.S. International Electricity Trade

The methodology used to project international electricity trade is based on projections by those utilities that import or export electricity. The utilities engaged in trade were identified from publications prepared by the Department of Energy's Office of Fuels Programs, planning documents for NERC regions and Canadian utilities. The information from these utilities ranged from specific amounts under contract to projections of trends. In the post-2000 period, proposed agreements were incorporated into the forecast based on the progress of current negotiations. These utility level estimates were aggregated to the Census and Federal Regions and discussed with officials at National Energy Board, Hydro-Quebec, Ontario Hydro, ERA, etc., and reconciled with published documents. The projections are shown in Table C10.

Table C10. Projected Net Electricity Imports to the United States from Canada and Mexico (Billion Kilowatthours)

Federal Region	1988	1989	1990	1995	2000	2005	2010
1	11.2	8.9	8.9	14.1	24.4	24.6	24.9
2	12.2	9.0	9.0	14.6	16.4	16.9	17.4
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	-0.8	0.0	1.2	5.3	7.7	7.2	7.2
6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	-0.4	0.7	1.0	2.6	2.6	3.4	4.3
9	5.5	3.4	4.3	4.5	3.2	4.4	4.7
10	4.1	4.0	3.0	4.4	5.8	7.8	9.2
Total	31.8	25.9	27.4	45.5	60.1	64.4	67.8

Assumptions for International Electricity Trade in the United States

- **Canadian Surplus Power**

  As a result of several years of drought in Canada, particularly in Manitoba and Quebec, surplus electricity is not available for export either now or in the near future. Quebec does not plan to make any surplus energy sales through the mid-1990's, only exchanges and firm power sales. Manitoba expects it to take almost a year to fully recover from the drought.

  Generating capacity in Ontario will be constrained. Ontario Hydro recently passed new coal emissions standards which limit their coal-fired generation. These standards will affect imports to New York and Michigan by reducing surplus electricity. The Darlington nuclear unit's in-service date has also been delayed by almost a year, which also reduces the potential for additional exports.

- **Canadian Demand for Electricity**

  In 1983, the Canadian National Energy Board (NEB) forecast Canadian electricity demand to grow by 3.2 percent per year.[1] Instead, since 1983, electricity demand has grown by 7.9 percent in 1984, 4.5 percent in 1985, 4.2 percent in 1986, 3.8 percent in 1987, and 5.7 percent in 1988, an average of 4.3 percent annually.[2] Therefore, there may not be as much surplus power available as previously believed because it will be needed to meet the additional domestic demand.

Cost of Capital, Outstanding Capital

Historical values for allowed return on equity, the cost of preferred stock, and the cost of long-term debt are used, along with the DRI forecast of the AA utility bond rating, to predict the future costs of debt and common and preferred equity. The cost of long-term debt, for example, is a function of the previous year's cost of debt and the previous year's AA utility bond rate.

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[1] NEB, *Canadian Energy—Supply and Demand 1983-2005* (September 1984), p. 40.
[2] NEB, *Annual Report* (March 1988 and 1989).

Historical allowed rates of return on equity for investor-owned electric utilities were obtained from the quarterly Utility Compustat II tape. Annual allowed rates of return were calculated by taking a simple average of each State's allowed rate of return for each company. Calculation of all the rates of return was limited to those companies and States for which Compustat provided an allowed rate of return.

For 1984 through 1987 rates of return on long-term debt and preferred stock were calculated with data from FERC Form 1. For 1988 these rates will be calculated with Annual Utility Compustat II data, because Form 1 data are not yet available.

Each company's contribution to regional and national rates was weighted by 1987 revenues by State from the EIA-861. This weighting method makes it possible to divide up utilities which operate in more than one region. However, it assumes that the relative size of each company's operations from 1984 through 1988 is the same as in 1987.

For 1984 through 1988 total rates of return based on Form 1 long-term debt and preferred stock average 17 basis points lower than total rates of return using Compustat data on long-term debt and preferred stock. Outstanding capital for investor-owned electric utilities from 1984 through 1987 are presented from the FERC Form 1.

Federal regions are presented in rows numbered 1 through 10; the total for the year is in the row designed by "T". Census regions are presented in rows designated "NC" for the Midwest, "NE" for the Northeast, "SO" for the South, and "WE" for the West. The annual total heads the census region rows.

The first three columns of Table C11 show the region, year, and number of observations. The next four columns show rates of return: the allowed rate of return on equity, the actual return on debt, the actual return on preferred, and the weighted return on total capital. The next four columns show capital structure: the percentages of equity, preferred, long-term debt, and short-term debt. The last five columns show actual capital investment in millions of dollars: equity, preferred, long-term debt, total capital, and short-term debt.

Table C11. Cost of Capital and Capitalization Percentage (Compustat Allowed, Form 1 Debt and Preferred)

FISCAL YEAR=84

REGION	YEAR	_FREQ_	ALWD_ROE	DEBTRATE	PREFRATE	TOT_ROR	EQ_PCT	PREF_PCT	LDBT_PCT	SDBT_PCT	EQUITY	PREFERRED	LTDEBT	CAPITAL	STDEBT
T	84	153	15.61	9.42	9.79	12.02	40.77	10.18	47.52	1.53	140895	36263	168139	350278	4981
1	84	15	15.62	9.50	9.21	11.83	36.85	10.31	48.72	4.12	4625	1362	6210	12702	505
2	84	11	15.57	8.44	7.64	11.63	45.28	10.02	43.49	1.21	15700	3621	15826	35538	391
3	84	18	15.38	9.02	8.92	11.41	38.37	11.57	48.69	1.37	18399	5434	23413	47820	575
4	84	18	15.34	9.83	8.82	11.95	39.74	9.96	49.19	1.11	20453	5313	24801	51123	556
5	84	29	15.92	9.82	13.45	12.62	40.12	9.44	48.75	1.69	29457	7154	36813	74795	1371
6	84	23	15.66	9.73	9.26	12.25	41.70	9.99	47.08	1.23	18496	4659	21808	45504	542
7	84	14	15.47	9.19	9.03	11.64	38.24	10.25	50.15	1.36	7771	2169	10514	20670	216
8	84	8	14.70	8.82	8.17	11.32	43.93	10.24	45.08	0.75	4901	1077	5084	11175	112
9	84	9	15.86	9.45	9.21	12.17	41.89	10.37	46.11	1.62	14254	3638	16157	34645	595
10	84	8	15.48	9.35	11.29	12.04	40.64	11.40	46.60	1.37	6839	1837	7513	16306	118

FISCAL YEAR=85

REGION	YEAR	_FREQ_	ALWD_ROE	DEBTRATE	PREFRATE	TOT_ROR	EQ_PCT	PREF_PCT	LDBT_PCT	SDBT_PCT	EQUITY	PREFERRED	LTDEBT	CAPITAL	STDEBT
T	85	158	15.58	9.42	9.66	11.92	41.45	9.57	47.88	1.09	156137	36541	18109	379489	3702
1	85	15	15.64	10.04	8.97	11.82	37.77	9.86	49.27	3.10	5046	1353	6715	13417	303
2	85	11	15.48	8.44	6.85	11.56	46.60	9.41	43.25	0.74	17377	3626	16846	38164	314
3	85	20	15.58	8.97	9.50	11.47	39.95	10.37	48.93	0.75	21482	5426	26350	53650	403
4	85	19	15.35	9.74	8.84	11.96	41.26	9.77	48.43	0.54	22238	5399	25843	53680	199
5	85	30	15.82	9.77	11.47	12.14	39.03	9.01	50.84	1.13	31503	7438	41493	81187	752
6	85	23	15.55	9.93	9.08	12.28	42.50	9.63	47.08	0.79	20330	4755	23698	49108	326
7	85	14	15.40	9.00	9.00	11.29	39.02	9.31	49.81	1.86	8482	2098	10967	21806	260
8	85	9	14.56	9.14	8.50	11.50	46.02	9.47	43.23	1.27	6786	1252	6346	14664	280
9	85	9	15.83	9.25	11.75	12.26	42.51	9.38	46.71	1.40	15426	3536	17416	36921	542
10	85	8	15.33	9.29	11.21	12.02	42.63	10.24	45.27	1.86	7467	1658	7434	16882	323

FISCAL YEAR=86

REGION	YEAR	_FREQ_	ALWD_ROE	DEBTRATE	PREFRATE	TOT_ROR	EQ_PCT	PREF_PCT	LDBT_PCT	SDBT_PCT	EQUITY	PREFERRED	LTDEBT	CAPITAL	STDEBT
T	86	162	15.20	9.41	9.20	11.71	42.16	8.73	47.62	1.49	167336	34977	193061	401225	5850
1	86	15	14.79	11.97	9.03	12.25	39.65	9.27	48.07	3.02	5159	1374	6859	13717	325
2	86	11	15.01	8.63	6.35	11.41	45.85	8.70	44.31	1.15	17725	3486	17985	39658	463
3	86	20	15.07	9.32	10.20	11.54	41.19	9.25	48.39	1.17	22517	4951	26743	54792	581
4	86	19	15.22	9.47	8.72	11.83	42.53	9.23	47.52	0.72	23817	5175	26690	56231	548
5	86	32	15.33	9.62	10.95	11.71	39.35	8.69	50.54	1.42	34417	7695	44259	87670	1297
6	86	23	15.28	9.59	8.89	12.03	43.18	9.11	47.32	0.39	22126	4745	25348	52368	149
7	86	15	15.28	8.74	9.10	11.27	41.38	7.41	49.43	1.78	9789	2060	12171	24306	286
8	86	9	14.56	8.94	8.29	11.43	46.14	8.17	44.57	1.11	6951	1040	6621	14933	321
9	86	9	15.53	8.92	8.81	11.76	43.90	7.48	45.25	3.38	16806	2986	17767	38877	1318
10	86	9	14.71	8.64	10.97	11.38	40.61	8.74	47.26	3.39	8029	1464	8618	18673	563

Table C11. Cost of Capital and Capitalization Percentage (Continued) (Compustat Allowed, Form 1 Debt and Preferred)

FISCAL YEAR=87

REGION	YEAR	_FREQ_	ALWD_ROE	DEBTRATE	PREFRATE	TOT_ROR	EQ_PCT	PREF_PCT	LDBT_PCT	SDBT_PCT	EQUITY	PREFERRED	LTDEBT	CAPITAL	STDEBT
T	87	162	14.60	8.49	7.97	11.04	41.25	7.74	47.56	2.39	172075	33232	198430	412577	8840
1	87	15	14.35	8.19	6.90	10.44	35.10	9.20	47.44	5.37	5198	1435	7113	14447	701
2	87	11	14.31	8.29	7.39	10.93	43.76	7.83	46.61	1.62	16679	3222	18535	38987	551
3	87	20	14.55	8.23	7.81	10.71	40.31	9.19	48.25	1.28	23398	5222	27971	57318	726
4	87	19	14.63	8.63	7.99	11.20	44.19	8.36	46.71	1.79	24978	5181	27719	58995	1077
5	87	32	14.95	8.64	8.74	11.36	39.69	7.20	49.46	2.04	35906	6933	44499	89093	1755
6	87	23	14.91	9.23	8.28	11.62	41.12	8.14	47.44	2.08	23078	4818	26400	55363	1067
7	87	15	13.62	8.19	6.82	10.57	42.78	5.33	49.77	2.64	9636	1606	12040	23729	446
8	87	9	14.56	8.35	7.07	11.11	43.22	7.05	44.87	2.07	7323	951	6809	15474	390
9	87	9	14.59	8.04	7.92	10.61	41.18	6.24	45.77	4.09	17484	2639	18963	40494	1408
10	87	9	13.59	8.37	8.57	10.75	40.46	6.89	45.55	5.37	8395	1224	8380	18717	718

FISCAL YEAR=88

REGION	YEAR	_FREQ_	ALWD_ROE	DEBTRATE	PREFRATE	TOT_ROR	EQ_PCT	PREF_PCT	LDBT_PCT	SDBT_PCT	EQUITY	PREFERRED	LTDEBT	CAPITAL	STDEBT
T	88	158	14.02	8.49	7.97	11.04	41.25	7.74	48.79	2.22	172228	32508	209654	425173	10783
1	88	15	13.95	8.19	6.90	10.44	35.10	9.20	51.56	4.15	4584	1462	7954	14437	437
2	88	11	13.65	8.29	7.39	10.93	43.76	7.83	46.76	1.66	16357	3062	18606	38674	649
3	88	20	13.86	8.23	7.81	10.71	40.31	9.19	48.77	1.72	24131	5418	29655	60308	1105
4	88	19	14.13	8.63	7.99	11.20	44.19	8.36	46.23	1.22	25948	5091	27670	59506	797
5	88	31	14.43	8.64	8.74	11.36	39.69	7.20	51.61	1.50	34596	6338	45602	87717	1181
6	89	23	14.56	9.23	8.28	11.62	41.12	8.14	49.08	1.67	23685	4856	28192	57489	755
7	88	15	13.20	8.19	6.82	10.57	42.78	5.33	49.70	2.18	9705	1430	11693	23257	429
8	88	7	14.26	8.35	7.07	11.11	43.22	7.05	43.72	6.01	6523	934	7514	16204	1233
9	88	9	13.50	8.04	7.92	10.61	41.18	6.24	47.92	4.66	16798	2627	19776	41223	2022
10	88	8	13.33	8.37	8.57	10.75	40.46	6.89	48.02	4.63	9901	1289	12991	26357	2176

Table C11. Cost of Capital and Capitalization Percentage (Continued) (Compustat Allowed, Form 1 Debt and Preferred)

FISCAL YEAR=84

CENSUS	YEAR	_FREQ_	ALWD_ROE	DEBTRATE	PREFRATE	TOT_ROR	EQ_PCT	PREF_PCT	LDBT_PCT	SDBT_PCT	EQUITY	PREFRRED	LTDEBT	CAPITAL	STDEBT
	84	153	15.61	9.42	9.79	12.02	40.77	10.18	47.52	1.53	140895	36263	168139	350278	4981
NC	84	47	15.83	9.69	12.65	12.43	39.85	9.58	48.95	1.62	38663	9622	48708	98605	1612
NE	84	30	15.67	9.11	8.39	11.82	41.01	10.79	46.11	2.10	25968	7150	30178	64552	1256
SO	84	51	15.37	9.44	8.93	11.83	40.69	10.04	48.17	1.09	49665	12722	59473	123047	1186
WE	84	25	15.69	9.41	9.42	12.08	41.89	10.49	46.10	1.52	26598	6768	29780	64074	927

FISCAL YEAR=85

CENSUS	YEAR	_FREQ_	ALWD_ROE	DEBTRATE	PREFRATE	TOT_ROR	EQ_PCT	PREF_PCT	LDBT_PCT	SDBT_PCT	EQUITY	PREFRRED	LTDEBT	CAPITAL	STDEBT
	85	158	15.58	9.42	9.66	11.92	41.45	9.57	47.88	1.09	156137	36541	183109	379489	3702
NC	85	48	15.74	9.64	11.04	12.00	39.09	9.05	50.61	1.24	41543	9828	53968	106401	1062
NE	85	32	15.68	9.15	8.25	11.68	42.23	10.02	46.55	1.20	30378	7341	34519	72951	712
SO	85	52	15.37	9.52	8.88	11.92	41.91	9.66	47.69	0.73	53869	12710	62252	129603	773
WE	85	26	15.61	9.28	11.25	12.15	42.89	9.51	46.16	1.45	30347	6662	32370	70533	1155

FISCAL YEAR=86

CENSUS	YEAR	_FREQ_	ALWD_ROE	DEBTRATE	PREFRATE	TOT_ROR	EQ_PCT	PREF_PCT	LDBT_PCT	SDBT_PCT	EQUITY	PREFRRED	LTDEBT	CAPITAL	STDEBT
	86	162	15.20	9.41	9.20	11.71	42.16	8.73	47.62	1.49	167336	34977	193061	401225	5850
NC	86	51	15.32	9.47	10.63	11.63	39.74	8.48	50.31	1.47	45851	10043	57923	115469	1652
NE	86	32	15.03	9.86	7.89	11.70	42.70	9.18	46.69	1.43	31294	6991	35934	75140	921
SO	86	52	15.18	9.29	9.11	11.81	42.78	9.08	47.34	0.79	57640	12353	65253	136368	1121
WE	86	27	15.29	8.90	9.09	11.68	43.82	7.73	45.42	3.04	32552	5589	33951	74248	2156

FISCAL YEAR=87

CENSUS	YEAR	_FREQ_	ALWD_ROE	DEBTRATE	PREFRATE	TOT_ROR	EQ_PCT	PREF_PCT	LDBT_PCT	SDBT_PCT	EQUITY	PREFRRED	LTDEBT	CAPITAL	STDEBT
	87	162	14.60	8.79	8.43	11.12	42.04	8.02	47.56	2.39	172075	33232	198430	412577	8840
NC	87	51	14.74	8.86	10.08	11.13	40.96	7.48	49.44	2.13	47268	8887	57993	116430	2282
NE	87	32	14.48	9.03	7.32	11.11	41.19	8.80	47.65	2.36	30384	6822	37100	75828	1521
SO	87	52	14.65	8.86	8.17	11.23	42.48	8.69	47.07	1.77	60574	12691	68317	143873	2292
NE	87	27	14.46	8.22	8.06	10.89	43.95	6.40	45.54	4.11	33849	4832	35020	76446	2744

FISCAL YEAR=88

CENSUS	YEAR	_FREQ_	ALWD_ROE	DEBTRATE	PREFRATE	TOT_ROR	EQ_PCT	PREF_PCT	LDBT_PCT	SDBT_PCT	EQUITY	PREFRRED	LTDEBT	CAPITAL	STDEBT
	88	158	14.02	8.49	7.97	11.04	41.25	7.74	48.79	2.22	172228	32508	209654	425173	10783
NC	88	50	14.22	8.56	8.43	11.23	40.27	6.90	51.22	1.60	46103	8156	58879	114763	1625
NE	88	32	13.88	8.39	7.51	11.87	40.38	8.69	48.82	2.11	29444	6786	38423	75986	1334
SO	88	52	14.16	8.69	7.96	11.18	42.64	8.33	47.44	1.58	63231	12758	71176	149472	2307
WE	88	24	13.59	8.14	7.98	10.71	41.14	6.41	47.72	4.73	33451	4809	41176	84952	5517

Corporate Bond Rates

Corporate bond rates are presented from the DRI annual forecast, Trendlong 25-year extension.

	AA Utility Bonds	90-Day Bonds
1984	13.65	9.52
1985	11.87	7.48
1986	8.94	5.98
1987	9.50	5.77
1988	10.10	6.67
1989	9.60	8.14
1990	8.59	6.69
1991	9.15	7.50
1992	9.72	7.23
1993	9.58	6.46
1994	9.37	6.11
1995	9.43	6.20
1996	9.39	6.12
1997	9.43	6.21
1998	9.29	6.10
1999	9.28	6.15
2000	9.40	6.33
2001	9.27	6.18
2002	9.26	6.19
2003	9.22	6.16
2004	9.20	6.17
2005	9.11	6.12
2006	9.09	6.14
2007	8.87	5.91
2008	8.94	6.00
2009	9.01	6.04
2010	9.09	6.08

Fuel Price Expectations

The life cycle costing methodology used in the *Electricity Market Module* requires price expectations for residual oil, distillate oil, natural gas, and coal.

Prices for residual fuel oil and distillate fuel oil are assumed to grow at the same rate as the world oil price. The wellhead price for natural gas is assumed to be a function of the world oil price. It is assumed to be 75 percent of the world oil price in the year 2000, 80% of the world oil price in 2005, and 85% of the world oil price in 2010 and beyond. Assumptions for the growth in the world oil price and the gas wellhead price (at the national level) are summarized below.

Expectations of World Oil Prices and Natural Gas Wellhead Prices for Life-Cycle Costing, 2000-2030
(1989 dollars)

	Oil		Natural Gas	
Year	($/bbl)	($/mmbtu)	($/mcf)	($/mmbtu)
2000	27.80	4.79	3.70	3.59
2005	32.90	5.67	4.68	4.54
2010	36.90	6.36	5.57	5.41
2015	39.90	6.88	6.03	5.85
2020	42.10	7.26	6.36	6.17
2025	44.30	7.64	6.69	6.49
2030	45.70	7.88	6.91	6.70

Coal prices are expected to increase due to increased coal production, which means opening new mines, and higher transportation costs due to higher fuel costs. Assumptions for delivered coal prices (at the regional level) are summarized below.

Expectations of Coal Prices for Life-Cycle Costing, 2000-2030
(1989 dollars per million Btu)

	Year						
Region	2000	2005	2010	2015	2020	2025	2030
1	2.14	2.32	2.35	2.38	2.42	2.45	2.48
2	1.85	1.93	1.95	1.96	1.98	2.00	2.04
3	1.63	1.65	1.66	1.67	1.69	1.70	1.71
4	1.89	1.91	1.94	1.95	1.98	2.00	2.03
5	1.80	1.82	1.85	1.86	1.88	1.90	1.93
6	2.10	2.12	2.15	2.16	2.16	2.20	2.22
7	1.68	1.68	1.68	1.68	1.69	1.69	1.70
8	1.30	1.34	1.40	1.44	1.49	1.53	1.59
9	1.70	1.71	1.73	1.75	1.77	1.79	1.81
10	2.12	2.32	2.53	2.74	2.94	3.16	3.37

Demand Side Management

New sources of power will be needed as the demand for electricity continues to grow. Utilities are expected to construct new generating facilities, purchase additional power from other utilities and nonutilities, and increase electricity imports in order to supply much of the needed electricity. In addition, many utilities (probably most) will also explore opportunities for reducing the demand they must satisfy using innovative demand-side-management (DSM) programs. While some utilities have already instituted DSM programs, their impact has been small. However, as the need for new sources of supply grows, the impact of utility DSM programs is expected to increase also.

At present, there is very little data to estimate the potential impact of utility DSM programs. The following discussion explains the assumptions made to estimate the impact of utility DSM programs for the NES Base Case.

The NES Base Case DSM impacts through 2000 are derived from the Electric Power Research Institute (EPRI) report *Impact of Demand-Side Management on Future Customer Electricity Demand*, EPRI EM-4815-SR, October 1986. In that report, EPRI forecast that by 2000, utility DSM programs would result in a reduction of 45 gigawatts of on-peak demand and 320 billion kilowatthours of reduced energy demand. However, of the 45 gigawatts of on-peak load reductions, over two thirds (31 gigawatts) is attributed to utility sponsored generation. In the EIA model, generation from cogenerators is included in nonutility generation and subtracted from the demand utilities must meet. Thus, utility-sponsored cogeneration must be removed from the EPRI data to avoid double counting.

In the publication, EPRI estimated that 13 of the 45 gigawatts of on peak reductions had already occurred in 1983 and a more current publication, the 1987 edition of *Generating Energy Alternatives* (Investor Responsibility Research Center Inc. ISBN0-931935-16-3) estimated that approximately 21 gigawatts of on-peak-demand reduction would be achieved through DSM programs in 1989. Using the same proportions for total energy demand would imply that DSM programs led to a reduction of 149 billion kilowatthours in demand in 1989. Thus, between 1989 and 2000, DSM programs are expected to result in a further reduction of 171 billion kilowatthours of demand. However, removing the amount associated with utility sponsored cogeneration (two thirds) leaves 57 billion kilowatthours of demand reduction due to utility DSM programs (excluding cogeneration programs). Between 2000 and 2010, it is assumed that an additional 171-billion-kilowatthour reduction in demand will be achieved through utility DSM programs. It is also assumed that of this 171 billion kilowatthour increase in DSM, the proportion accounted for by utility sponsored cogeneration will decline to one third by 2010. Table C12 summarizes these assumptions.

Table C12. Demand Reductions Due to Demand-Side Management Programs (Billion Kilowatthours)

	1989	2000	2010
Total	149	320	491
Already Achieved in 1989	-149	-149	-149
Utility-Sponsored Cogeneration	--	-114	-171
Net Demand Reduction	0	57	171

Because of the lack of data, the national DSM impacts are shared to the Census (and DOE) regions (and end-use sectors) based on each region's (and sector's) share of electricity sales. To reflect the costs associated with these programs each kilowatthour of demand reduction caused by utility DSM programs will be priced at 80 percent of the cost of power from a new combined-cycle unit.

Nonutilities

Nonutility electricity supply is expected to grow. Additional nonutility growth is expected in the future because 1) there has been generally successful experience by utilities, regulators, the financial community, and by nonutility suppliers; 2) markets among the states have become increasingly open (for example, growth in competitive bidding); and 3) technological improvements are expected to continue.

Nonutility electricity estimates for 1988 are derived from 1987 data provided by the Edison Electric Institute (EEI). The 1988 nonutility sales to utilities are obtained from the Form EIA-861, "Annual Electric Utility Report." Forecast values for fossil-fueled nonutility supply (natural gas, coal, oil) are a share of utility capacity growth requirements projected in the EIA Electricity Market Module (EMM) of the Intermediate Future Forecasting System (IFFS). Total industrial self-generation growth is assumed to be 14 percent of its total electricity demand growth forecast in the EMM, continuing its present share of industrial electricity demand. Commercial generation for self use is assumed by EIA to be 5 percent of total commercial electricity demand growth, representing a slight increase over self-generation's current share of total commercial electricity demand. Fossil fuels' shares of each sector's self-generation growth are derived from their 1987 share among EEI data, modified by the effects of fuel costs and retail electricity prices in each sector. Projections for renewable resources are derived from projections provided by the Office of Conservation and Renewable Energy (CE), modified to reflect utility capacity requirements.

CE projections for each renewable technology are based upon measures of existing capacity and current construction, data and projections on economic performance (under assumptions of continuations in current technological improvements without breakthroughs), and consideration of each technology's prospects vis-a-vis EIA's projected demand requirements and projected costs of competing technologies. The CE projections include estimation of the effects of EIA fuel costs projections on technology choices.

Projections of nonutility markets are very uncertain, even under the base case assumptions of current laws and regulations. Market experience under PURPA is too brief to facilitate reliable forecasts. Further, the extent to which utilities and regulators will accommodate additional competition and participation, possibly from large independent power producers (IPPs), or build plants themselves, is very unclear. The rapid growth of new generation and the variety of alternatives further serve to make nonutility markets volatile and uncertain.

The projections for nonutility (and utility) renewables provided by CE were lowered because EIA forecast requirements for new peaking capacity are well below the levels implicit in the original CE forecasts. Wind-powered capacity, currently over 1000 megawatts and with contracts for several hundred more by 2000 in the West, was eliminated prior to 2000 for all other regions and reduced after 2000, particularly in the Southwest. Solar thermal projections, including those in the West, were similarly reduced. At the same time, after 2000, much renewables capacity for wind, solar thermal, and photovoltaic technologies originally projected by CE for utilities, was shifted to the nonutility sector. Finally, storage technology projections were revised to include nonutility hydroelectric pumped storage capacity growth (about 2.5 GW by 2010) and for battery and air storage technologies, (8.0 GW by 2010). By agreement, however, storage technologies are no longer categorized among renewable sources.

Nonutility electricity supply is assumed to grow from 31 GW in 1988 to 67 GW in 2000 and to 111 GW in 2010 (12 percent of total capacity by 2010). The share of total nonutility generation sold to utilities will exceed 60 percent by 2010, as plants are increasingly built for utility supply.

Table C13. Nonutility Supply

	1988	2000	2010
		Capacity (Gigawatts)	
Fossil	21.6	44.2	71.3
Nonfossil/Other[a]	9.8	22.4	39.2
Total	31.4	66.6	110.5
		Generation (Billion Kilowatthours)	
Sales to Utilities	69	204	334
For Own Use	110	147	206
Total	179	351	543

[a] Nonfossil/other includes renewable sources such as hydroelectric power, geothermal, wind, solar, ocean thermal, biomass, wood, and waste, and fossil waste products, and, after 2000, hydroelectric pumped storage, battery, and compressed air capacity.

Renewable Sources

Electricity generating technologies using renewable energy sources include conventional hydroelectric power, geothermal, wind, solar thermal and photovoltaic, ocean thermal, and biomass, wood, and waste sources. Hydroelectric power dates from the earliest years of the electric utility industry and still provides over 10 percent of generation. Other renewable sources are currently providing very small amounts of generation (with regional exceptions). However, rising fossil fuel costs, environmental and security concerns, and technological improvements in using renewable fuels, all suggest that utilities will make greater use of renewable sources in the future than in the recent past. The use of renewable fuels has grown most rapidly in the nonutility sector where, encouraged by PURPA, small power producers (largely concentrated in California) have introduced both demonstration and general production units.

Renewable energy data for electric utilities are provided by the Form EIA-860, "Annual Electric Generator Report," through 1999. Utility renewable capacity increments from 2000 through 2010 are derived from projections by CE as described above. Renewable energy data for 1988 for nonutilities are derived from 1987 Edison Electric Institute data. In addition to revisions for renewables noted for wind, solar thermal, and photovoltaics, above, EIA also reduced CE estimates for biomass to account for less optimistic expectations, environmental concerns, current slowdown in the industry, and uncertainty about biomass economics.

Table C14. Renewable Sources of Electricity (Megawatts)

	1988	2000	2010
Utility			
Conventional Hydroelectric	73,493	74,241	74,241
Photovoltaic	3	21	619
Solar Thermal	10	10	1,350
Wind	5	4	1,472
Geothermal	1,667	1,844	3,794
Biomass/Wood/Waste	443	523	1,299
Total Utility Renewables	75,621	76,643	82,775
Nonutility			
Conventional Hydroelectric	1,247	3,030	3,440
Photovoltaic	0	141	1,229
Solar Thermal	305	1,001	1,928
Wind	1,175	2,143	4,357
Geothermal	1,129	1,752	2,702
Biomass/Wood/Waste	5,968	14,294	20,850
Total Nonutility Renewables	9,824	22,360	34,507
Storage			
Utility Pumped Storage	17,032	19,510	19,510
Utility Other Storage	0	0	3,000
Nonutility Pumped/Other	0	0	0

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